CANADA

National Energy Board

Reasons for Decision

Alberta Natural Gas Company Ltd.

GHW-2-91

May 1992

Facilities

National Energy Board

Reasons for Decision

Alberta Natural Gas Company Ltd.

Application dated 31 May 1992,
as amended, for
1993 Facilities Expansion

GHW-2-91

May 1992

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Recital and Submittors

IN THE MATTER OF the *National Energy Board Act* ("the Act") and the Regulations made thereunder; and

IN THE MATTER OF an application dated 31 May 1990, as amended, by Alberta Natural Gas Company Ltd. for an order, pursuant to section 58 of the Act, requesting exemption from paragraphs 30, 31, and 47 of the Act in respect of certain facilities proposed to be added to its pipeline system, filed with the Board under File 3400-A2-11; and

IN THE MATTER OF National Energy Board Directions on Procedure, Order GHW-2-91, as amended.

EXAMINED by means of written submissions.

BEFORE

R. Priddle	Presiding Member
J.-G. Fredette	Member
R.B. Horner	Member
A.B. Gilmour	Member
A. Côté-Verhaaf	Member
C. Bélanger	Member
R. Illing	Member
K.W. Vollman	Member
R. Andrew	Member

SUBMITTORS

Alberta Petroleum Marketing Commission
Altamont Gas Transmission Canada Limited and Altamont Gas Transmission Company
Amoco Canada Petroleum Company Ltd.
Canadian Petroleum Association
CanWest Gas Supply Inc.
Chevron Canada Resources
Czar Resources Ltd.
Foothills Pipe Lines Ltd.
Independent Petroleum Association of Canada
Indicated Expansion Shippers (group comprised of Chevron Canada Resources, North Canadian Marketing Inc., and Petro-Canada; joint submission made with Norcen Marketing Inc.)
Mobil Oil Canada
Northern California Power Agency
Northwest Natural Gas Company
Pacific Gas Transmission Company
Pan-Alberta Gas Ltd.
Paramount Resources Ltd.
Poco Petroleums Ltd.
Sacramento Municipal Utility District

San Diego Gas & Electric Company
Southern California Edison Company
Summit Resources Limited
Suncor Inc.
Unigas Corporation
Vector Energy Inc.
Washington Energy Resources, Inc.
Western Gas Marketing Limited

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Abbreviations

Act	*National Energy Board Act*
AEC	Alberta Energy Company Ltd.
AERCB	Alberta Energy Resources Conservation Board
AFUDC	allowance for funds used during construction
Altamont	Altamont Gas Transmission Company
Amerada Hess	Amerada Hess Canada Ltd.
Amoco	Amoco Canada Petroleum Company Ltd.
ANG	Alberta Natural Gas Company Ltd.
ANG Market Study	Market study prepared on behalf of ANG by RECON Research Corporation entitled "Market Study in Support of ANG Facilities Expansion"
APMC	Alberta Petroleum Marketing Commission
A&S	Alberta & Southern Gas Co. Ltd.
Bcf	billion cubic feet
Bcfd	billion cubic feet per day
B.C.	British Columbia
BC Gas	BC Gas Inc.
Board	National Energy Board
Bow Valley	Bow Valley Industries Ltd.
Burbank	the City of Burbank
CanHunter	Canadian Hunter Marketing Ltd.
CanWest	CanWest Gas Supply Inc.
Cascade	Cascade Natural Gas Corporation
Chevron	Chevron Canada Resources
the Company	Alberta Natural Gas Company Ltd.
CPA	Canadian Petroleum Association
C.P. National	C.P. National Corporation
CPUC	California Public Utilities Commission
Czar	Czar Resources ltd.
DEKALB	DEKALB Energy Canada Ltd.
DOE/FE	U.S. Department of Energy / Office of Fossil Energy

EARP Guidelines Order	*Environmental Assessment and Review Process Guidelines Order*
El Paso	El Paso Natural Gas Company
Esso	Esso Resources Canada Limited
EOR	enhanced oil recovery
FERC	U.S. Federal Energy Regulatory Commission
Foothills	Foothills Pipe Lines Ltd.
Foothills (South B.C.)	Foothills Pipe Lines (South B.C.) Ltd.
Glendale	the City of Glendale
Grand Valley	Grand Valley Gas Company
HP	horsepower
Husky Oil	Husky Oil Operations Ltd.
IES	group comprised of Chevron Canada Resources, North Canadian Marketing Inc., and Petro-Canada (collectively referred to as the Indicated Expansion Shippers), along with Norcen Marketing Inc.
IGI	IGI Resources, Inc.
Inverness	Inverness Petroleum Ltd.
IPAC	the Independent Petroleum Association of Canada
Kern River	Kern River Gas Transmission Company
LDC	local distribution company
m^3	cubic metre
m^3/d	cubic metres per day
Mcf	thousand cubic feet
Mobil	Mobil Oil Canada
mm	millimetre
MMcfd	million cubic feet per day
Mojave	Mojave Pipeline Company
MW	megawatt
NCMI	North Canadian Marketing, Inc.
NCO	North Canadian Oils Limited
NCPA	Northen California Power Agency
NGV	natural gas vehicle
Norcen	Norcen Energy Resources Limited
Northridge	Northridge Alberta Gas Sales Ltd.

Northwest Pipeline	Northwest Pipeline Corporation
Northwest Natural Gas	Northwest Natural Gas Company
NOVA	NOVA Corporation of Alberta
NPA	Northern Pipeline Agency
OD	outside diameter
OEM	original equipment manufacturer
PAGUS	Pan-Alberta Gas (U.S.) Inc.
Pan-Alberta	Pan-Alberta Gas Ltd.
PanCanadian	PanCanadian Petroleum Limited
Pancontinental	Pancontinental Oil, Ltd.
Pasadena	the City of Pasadena
PG&E	Pacific Gas & Electric Company
PGT	Pacific Gas Transmission Company
Poco	Poco Petroleums Ltd.
Salmon	Salmon Resources Limited
SDG&E	San Diego Gas & Electric Company
Shell	Shell Canada Limited
SMUD	Sacramento Municipal Utility District
SoCal Edison	Southern California Edison Company
SoCal Gas	Southern California Gas Company
Summit	Summit Resources Ltd.
Suncor	Suncor Inc.
Tcf	trillion cubic feet
TransCanada	TransCanada PipeLines Limited
Transwestern	Transwestern Pipeline Company
UEG	utility electric generation
Unigas	Unigas Corporation
Vector	Vector Energy Inc.
Washington Energy	Washington Energy Exploration, Inc.
WCSB	Western Canada Sedimentary Basin
Westcoast	Westcoast Energy Inc.
WGML	Western Gas Marketing Limited
WWP	Washington Water Power

Overview

(Note: This overview is provided solely for the convenience of the reader and does not constitute part of this Decision or the Reasons, to which readers are referred for detailed text and tables.)

The Application

On 31 May 1990, Alberta Natural Gas Company Ltd. ("ANG" or "the Company") filed an application with the National Energy Board ("the Board") pursuant to Part III of the *National Energy Board Act* ("the Act") for an order authorizing an expansion of its transmission pipeline system in southern British Columbia. ANG's proposed expansion facilities consist of additional and modified facilities at its three existing compressor stations, at an estimated capital cost of approximately $82 million (in 1990 dollars).

The proposed ANG expansion, together with a planned facilities expansion by Foothills Pipe Lines (South B.C.) Ltd., is designed to increase the export capacity at Kingsgate, B.C. by 24.7 $10^6m^3/d$ (872 MMcfd) to serve new markets in California and the U.S. Pacific Northwest. The targeted in-service date is 1 November 1993.

Economic Feasibility

In support of its application, ANG filed copies of the binding, unconditional firm transportation contracts that had been signed by the prospective expansion shippers for the full expansion volume. ANG advanced the view that these contracts, backed by financial assurances, provide concrete evidence that the expansion facilities would be used at reasonable levels and that the associated demand charges would be paid.

In the Board's view, the unconditional firm transportation contracts signed by the prospective expansion shippers provide strong, although not conclusive, evidence that the expansion facilities would be used at a reasonable level over their economic life and that the associated demand charges would be paid.

In determining whether the expansion facilities are in the public interest, the Board also took into account the overall supply and market information filed in support of the application together with the available project-specific supply and market information, as well as information provided in respect of the competitiveness of Canadian-sourced gas in the California and Pacific Northwest markets targeted by the expansion. The Board believes that this evidence, coupled with the existence of executed long-term, unconditional firm service transportation contracts for the entire expansion volume, satisfactorily demonstrates that markets will exist in California and the Pacific Northwest for the expansion volumes, and that Canadian-sourced gas could be competitive in those markets.

Moreover, the Board is of the view that the toll increase on ANG that would be caused by the expansion would not result in reduced demand for firm service on the system.

Environmental Screening

The Board conducted an environmental screening of the expansion proposal pursuant to the Environmental Assessment and Review Process Guidelines Order, to the extent that there was no duplication with the Board's own regulatory process. The Board determined that the potentially adverse environmental effects which may be caused by the proposed facilities, including the social effects directly related thereto, would be insignificant or mitigable with known technology.

The Board accepted ANG's undertaking to prepare an Environmental Impact Analysis and conditioned its approval upon the Company filing the document for Board approval in advance of construction.

Order XG-16-92

The Board concluded that the applied-for expansion facilities are in the public interest. Accordingly, the Board has issued, pursuant to section 58 of the Act, Order XG-16-92 exempting ANG from the provisions of sections 30, 31, and 47 of the Act in respect of the expansion facilities.

Chapter 1
Background

1.1 The Application

On 31 May 1990, Alberta Natural Gas Company Ltd. ("ANG" or "the Company") filed an application with the National Energy Board ("the Board") pursuant to Part III of the *National Energy Board Act* ("the Act") for an order authorizing an expansion of its transmission pipeline system in southern British Columbia ("B.C."). ANG later filed a series of amendments to its application by a letter dated 2 October 1991.

The proposed ANG expansion, together with a planned facilities expansion by Foothills Pipe Lines (South B.C.) Ltd. ("Foothills (South B.C.)"), is designed to increase the export capacity at Kingsgate, B.C. by 24.7 $10^6m^3/d$ (872 MMcfd) to serve new markets in California and the U.S. Pacific Northwest. The targeted in-service date is 1 November 1993.

ANG's proposed expansion facilities consist of additional and modified facilities at its three existing compressor stations, as more particularly described below:

(1) Compressor Station No. 1: installation of two additional compressor units in separate buildings, replacement of three aerodynamic assemblies, additional gas scrubbing capacity, an additional control building, additional cooling capacity, and piping additions. This would provide a power increase of approximately 28 MW (37,500 HP);

(2) Compressor Station No. 2A: installation of cooling facilities, replacement of an aerodynamic assembly, additions and modifications to yard piping, replacement of the existing gas scrubber, and the addition of a second gas scrubber; and

(3) Compressor Station No. 2B: installation of an additional compressor unit in a separate building, control additions in the existing control building, replacement of an aerodynamic assembly, additions and modifications to the yard piping, and installation of an additional gas scrubber. This would provide a power increase of approximately 14 MW (18,750 HP).

ANG stated in its application that the expansion facilities are scheduled to be installed during 1993 at an estimated capital cost of approximately $82 million (in 1990 dollars).

1.2 Pipeline Expansion Project

The proposed ANG expansion is part of an overall expansion of the existing Alberta - northern California natural gas transmission pipeline system owned, from north to south, by ANG and Foothills (South B.C.), Pacific Gas Transmission Company ("PGT"), and Pacific Gas and Electric Company ("PG&E"). Figure 1-1 shows the route of the overall pipeline system. Figure 1-2 shows the route of that part of the system located in southern B.C.

On the Canadian side of the border, the Board exercises jurisdiction over both ANG and Foothills (South B.C.). As shown on Figure 1-2, these two companies own pipeline facilities in southeastern B.C. which connect upstream with the facilities of NOVA Corporation of Alberta ("NOVA") near Crowsnest, Alberta and downstream with the PGT system at the international

Figure 1-1
Pipeline Expansion Project
Connecting Systems

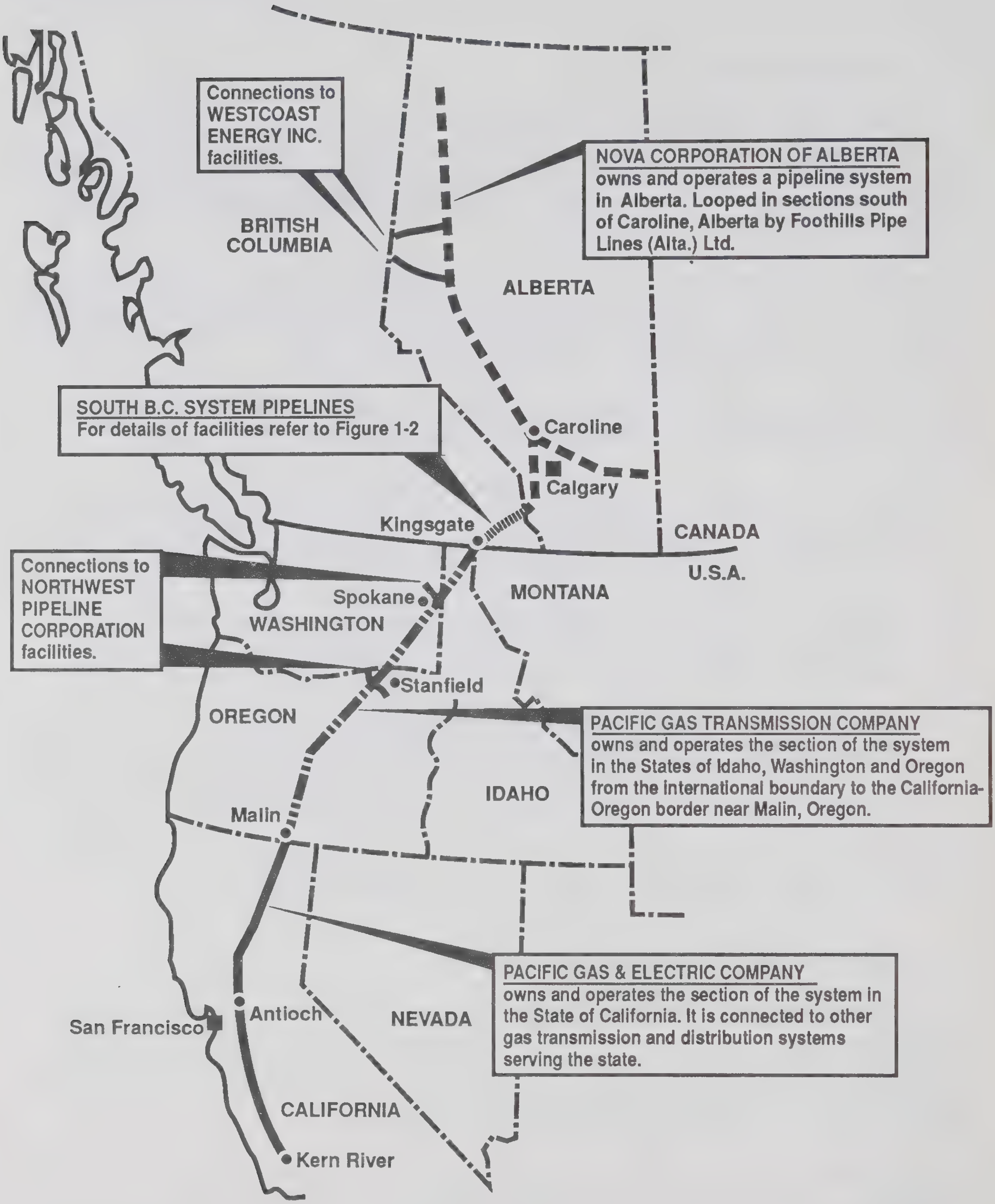
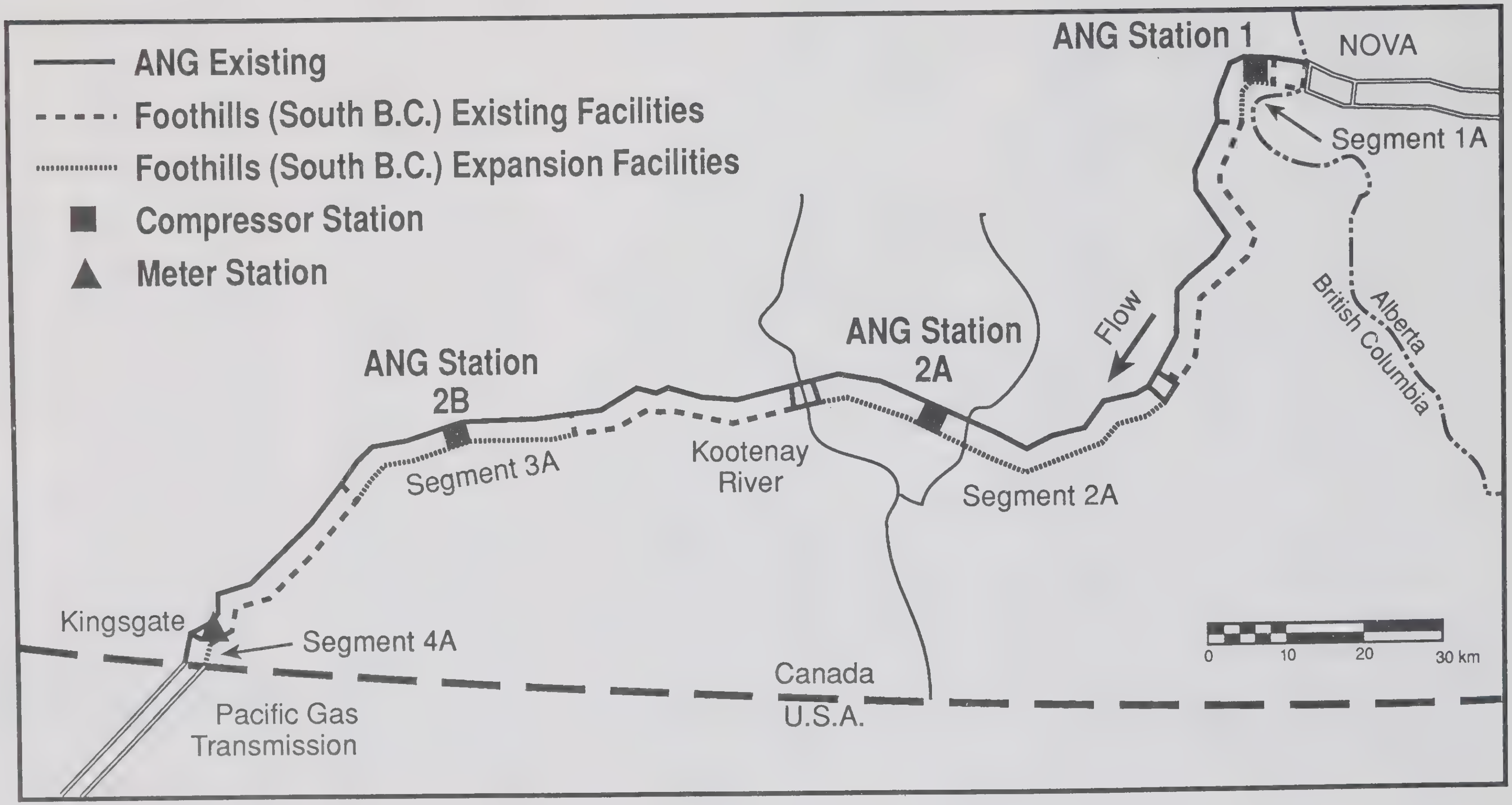


Figure 1-2
Alberta Natural Gas / Foothills (South B.C.)
Proposed South B.C. Expansion



boundary near Kingsgate, B.C. NOVA would also have to expand its facilities in order to accommodate the expansion volumes, at a net cost of about $312 million (current dollars)[1].

The existing facilities of ANG consist of a 914 mm (36 inch) OD mainline, 170.7 km (106 miles) in length, running from Crowsnest to the international boundary, four loops totalling 6.6 km (4.1 miles) in length, three compressor stations located near Crowsnest, Elko, and Moyie, and metering facilities located near Kingsgate.

Foothills (South B.C.) currently owns four segments of 914 mm (36 inch) OD pipe, totalling 87.6 km (54.4 miles), running parallel to ANG's mainline, as well as metering facilities at Kingsgate. The facilities owned by Foothills (South B.C.) are operated by ANG.

In conjunction with the expansion, Foothills (South B.C.) plans to complete its looping of the ANG mainline by installing four additional segments of 1067 mm (42 inch) OD pipe totalling 77.5 km (48.2 miles) at an estimated capital cost of about $105 million (1990 dollars). This would complete Zone 8 of the Canadian portion of the Alaska Natural Gas Transportation System, already certificated under the *Northern Pipeline Act*.

South of the international border, PGT proposes to complete the looping of its existing 914 mm (36 inch) OD mainline by installing 692 km (430 miles) of 1067 mm (42 inch) OD pipe. Complementing that looping would be 37 MW (49,600 HP) of extra compression through the addition of one new and two replacement gas turbine compressor units at existing stations.

The PG&E component of the expansion involves the installation of some 667 km (415 miles) of 914 mm (36 inch) OD and 1067 mm (42 inch) OD pipeline looping, 19.5 MW (26,100 HP) of additional compression, and assorted other system modifications.

Combined, the PGT and PG&E components of the expansion are forecast to cost in the order of $1.6 billion (current U.S. dollars)[2].

1.3 Directions on Procedure

On 10 September 1991, the Board issued Order GHW-2-91 setting out Directions on Procedure to be followed in respect of the application. An amendment to the Order, AO-1-GHW-2-91, followed on 5 November 1991.

In brief, these Directions provided interested parties the opportunity to comment on the application through written submissions, and ANG the right to file a written reply to those submissions. This process attracted submissions from 26 parties, including major industry associations and the majority of the expansion shippers.

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1. On 31 October 1991, the Government of Alberta issued Order in Council 715/91 requiring that the Alberta Energy Resources Conservation Board ("AERCB") call for, and make available for public evaluation, information to clarify proposals by ANG/Foothills/PGT/PG&E and Altamont Gas Transmission Company ("Altamont") to construct pipeline facilities to transport gas from Alberta to California markets. Details of the NOVA facilities that would be required to accommodate the two projects were outlined in a submission made by NOVA to the AERCB on 17 January 1992 in conjunction with the Call for Information.

2. Reference submission made by ANG/Foothills/PGT/PG&E to the AERCB on 30 December 1991 in respect of the AERCB's Call for Information into the PGT Expansion and Altamont pipeline proposals.

Chapter 2
Gas Supply

In considering ANG's application, the Board examined two aspects of gas supply: overall gas supply (subsection 2.1) and project-specific gas supply (subsection 2.2). Overall gas supply refers to the total supply of natural gas that will be available to the ANG system as well as to other Canadian pipeline systems. In this regard, the Board considered whether there would be adequate gas supply to support the planned throughput of the total ANG pipeline system over the economic life of the facilities.

Project-specific gas supply refers to the gas supply in respect of new requests for service associated with the proposed expansion. In this regard, the Board examined whether each shipper had secured or would secure adequate gas supply to meet its obligations, and examined the general characteristics of each shipper's supply.

2.1 Overall Gas Supply

To demonstrate the adequacy of overall gas supply, ANG relied upon a study it conducted of future natural gas supply availability[1]. An underlying assumption of the study was that future improvements in technology would result in increases in economically recoverable reserves and corresponding lower real supply costs. That is, the projections made in the study are based on a supply function which assumes that economically recoverable reserves would increase by approximately ten percent every five years matched with reductions in real supply costs of a similar magnitude. The study results were compared to the Low Price Scenario demand projection in the Board's *Canadian Energy Supply and Demand 1987-2005* report (dated September 1988), with an allowance for recently approved export licences and the applied-for ANG volumes. The study concluded that there would be adequate natural gas supply to support the planned throughput of ANG's total pipeline system in the long term.

Views of the Board

In contrast to ANG's analysis, the Board's projections are based on progressively increasing supply costs to a maximum level. Accordingly, the Board's view is that higher gas prices would be required to increase the level of economically recoverable reserves. The Board's analysis of the future growth of gas supply, demand and prices over time does suggest, however, that although supply cost is rising, sufficient reserves and productive capacity would become available over the term of the useful life of the facilities to support the planned throughput of the proposed ANG expansion.

The Board recognizes that there are many uncertainties regarding the future course of supply costs and prices. However, the Board is of the view that there will be adequate overall Canadian gas supply to allow the full use of ANG's expanded pipeline capacity in the long term.

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1 Study prepared on behalf of ANG by D.E. Armstrong and Carl Calantone of McGill University and Zafar Khan of Monenco Consultants.

2.2 Project-specific Gas Supply Arrangements

ANG submitted evidence demonstrating that gas supply arrangements were in place for 24 of the 28 expansion shippers (a description of these gas supply arrangements can be found in Appendix I). The quantities under these gas supply arrangements correspond to about 90 percent of the aggregate required expansion volume. The remaining four shippers expect to conclude their gas supply arrangements shortly.

In general, those shippers which are also producers or aggregators are relying on their corporate supply pools to provide the contracted volumes. The corporate supply pools for these shippers are large, ranging from 7.1 10^9m^3 (250 Bcf) to 71 10^9m^3 (2.5 Tcf). This group of shippers comprises about 45 percent of the proposed expansion volumes. The remaining shippers, which are not producers or aggregators, have executed gas purchase contracts varying in length from six to fifteen years and for volumes ranging from 71 10^3m^3/d (2.5 MMcfd) to 1 500 10^3m^3/d (53 MMcfd). As of the end of February 1992, eleven export applications, with terms up to 15 years and representing about 30 percent of the total expansion volume, had been received by the Board from four shippers. The detailed information provided in these applications corresponds closely to the information outlined by ANG in its evidence on project-specific supply.

Views of the Board

On the basis of the evidence that supply arrangements for 90 percent of the expansion volumes are in place and on the expectation that arrangements for the remaining 10 percent will be in place shortly, the Board is satisfied with the adequacy of the project-specific supply arrangements supporting ANG's proposed expansion.

Chapter 3
Requirements

ANG has applied to expand its facilities to provide transportation service to 28 export shippers who intend to market Canadian-sourced gas in the U.S. Pacific Northwest and California markets commencing in November 1993. In addition, the expansion facilities would provide service to one domestic shipper serving an off-line market in B.C. (reference subsection 3.2 "Project-specific Markets" and Appendix II).

In support of its facilities application, ANG provided overall, long-term natural gas market forecasts for the Pacific Northwest and California markets. In addition, ANG provided the available information with respect to the project-specific markets intended to be served by the individual expansion shippers and the status of the associated Canadian and U.S. regulatory approvals.

3.1 Overall Market Requirements

In support of its overall Pacific Northwest and California market assessments, ANG filed, in June 1991, a market study prepared by RECON Research Corporation entitled "Market Study in Support of ANG Facilities Expansion" ("ANG Market Study").

In February 1992, ANG filed copies of the market information filed by ANG/Foothills (South B.C.)/PGT/PG&E six weeks earlier in respect of the AERCB's Call for Information into the PGT Expansion and Altamont pipeline proposals. This filing essentially updated ANG's originally-filed assessment of the Pacific Northwest and California markets. Specifically, ANG's revised assessment encompassed publication of the *1991 California Gas Report*[1] and recognized the Pacific Northwest Local Distribution Companies' ("LDCs'") least cost plans.

3.1.1 Pacific Northwest

Total gas demand in the Pacific Northwest[2] is forecast to increase from 926 MMcfd in 1992 to 1,340 MMcfd by 2011, or 2.0 percent per year on an average annual basis (reference Table 3-1).

The ANG Market Study noted that the Pacific Northwest market has subscribed for PGT capacity to:

- firm up existing interruptible transportation of Alberta-sourced gas on PGT;
- allow customers to obtain service directly off the PGT system instead of indirectly via the Northwest Pipeline system; and
- to allow the market to access incremental gas supplies, to diversify its sources of supply, and to satisfy its winter peak day demand.

1 The *California Gas Report* is prepared annually by the California utilities and is published by the California Public Utilities Commission ("CPUC"). The report reflects those utilities' estimates of future gas demand in their service areas.

2. The Pacific Northwest market is comprised of the states of Idaho, Oregon, and Washington.

TABLE 3-1

PACIFIC NORTHWEST GAS DEMAND
(MMcfd)

	1992	1993	1994	1995	2000	2005	2011
RESIDENTIAL	232	243	254	266	317	359	400
COMMERCIAL	162	166	170	174	194	209	234
INDUSTRIAL	499	505	508	509	515	520	526
ELECTRIC GENERATION	28	71	158	158	165	165	165
OTHER	5	6	6	7	9	11	15
TOTAL	927	991	1 097	1 114	1 200	1 264	1 340

Source: ANG filing with respect to the AERCB's "Call for Information - Altamont and PGT Pipeline Projects", Proceeding 911586, "General Demand/Supply Information Requirement", Table 1-13.

The Pacific Northwest is served by six distribution utilities, including Cascade Natural Gas Corporation ("Cascade"), Northwest Natural Gas Company ("Northwest Natural Gas"), Washington Natural Gas, and Washington Water Power ("WWP"). The market is also served by two interstate pipeline systems, Northwest Pipeline and PGT.

The forecast of residential, commercial and industrial demand (i.e. that portion of the industrial demand served by the LDCs) is an aggregation of the various forecasts prepared by the aforementioned LDCs and is based upon, among other things, the following assumptions:

- gas will continue to be priced competitively with electricity;
- franchise areas will expand as the region's population and industrial base continue to grow; and
- the rate of conversion from oil to gas will increase.

Residential gas demand is forecast to grow from 232 MMcfd in 1992 to 400 MMcfd in 2011, or by 2.9 percent per year on an average annual basis. Commercial gas demand is forecast to grow from 162 MMcfd in 1992 to 234 MMcfd in 2011, or by 2.0 percent per year on an average annual basis. The growth in both the residential and commercial markets reflects continued population growth and the conversion of electric space heating units and hot water systems to gas.

The industrial market is forecast to grow from 499 MMcfd in 1992 to 526 MMcfd in 2011. The ANG Market Study noted that year-to-year fluctuations in industrial gas consumption reflected the changes in oil prices and fuel switching by some industrial customers.

Gas consumption in the electric generation market sector is forecast to grow from 28 MMcfd in 1992 to 165 MMcfd by 1998 and remain steady at that level to the end of the forecast period. Competitive gas pricing and the impact of low water supplies on hydroelectric generation were identified as two reasons for the recent increase in gas consumption for electricity generation. Gas consumption in this sector of the market is forecast to increase by 21.5 percent per year over the 1992 to 2001 period and by 9.7 percent per year over the 1992 to 2011 period, on an average annual basis.

The ANG Market Study concluded that gas-fired combustion turbines and cogeneration facilities will likely meet future electricity demand since the potential to develop additional low-cost hydroelectric resources has been almost exhausted.

Demand for Interstate Pipeline Capacity

The ANG Market Study revealed that, after allowing for the proposed PGT expansion and the new services proposed by Northwest Pipeline, the anticipated annual average load factor for end-use delivery capacity into the Pacific Northwest does not fully support the firm delivery capacity increments requested by the shippers on the PGT and Northwest Pipeline expansions (reference Table 3-2).

The ANG Market Study noted that, while Tables 3-1 and 3-2 accurately reflect the forecast of average daily demand in the Pacific Northwest, they do "not comprehensively reflect the demand for pipeline capacity because the Pacific Northwest gas demands are highly seasonal". Specifically, the residential, commercial, and Utility Electric Generation ("UEG") loads peak in the winter.

The peak day requirements in the Pacific Northwest are forecast to increase from 2,299 MMcfd in 1992 to 3,433 MMcfd in 2011 (reference Table 3-3).

TABLE 3-2

PACIFIC NORTHWEST AVERAGE DAY INTERSTATE PIPELINE CAPACITY UTILIZATION

(MMcfd)

	1992	1993	1994	1995	2000	2005	2011
END-USE DEMAND	927	991	1 097	1 113	1 200	1 264	1 340
EXISTING CAPACITY:							
Firm Sales	234	234	234	234	234	234	234
Firm Transportation	886	886	886	886	886	886	886
TOTAL EXISTING	1 120	1 120	1 120	1 120	1 120	1 120	1 120
EXPANSIONS:							
PGT	0	25	148	148	148	148	148
Northwest	0	118	237	237	237	237	237
TOTAL EXPANSIONS	0	143	385	385	385	385	385
TOTAL CAPACITY	1 120	1 263	1 505	1 505	1 505	1 505	1 505
LOAD FACTOR	82.8%	78.5%	72.9%	74.0%	79.7%	84.0%	89.1%

Source: ANG filing with respect to the AERCB's "Call for Information - Altamont and PGT Pipeline Projects", Proceeding 911586, "General Demand/Supply Information Requirements", Table 1-15.

TABLE 3-3

PACIFIC NORTHWEST PEAK DAY CAPACITY REQUIREMENTS
(MMcfd)

	1992	1993	1994	1995	2000	2005	2011
FIRM	1 826	1 881	1 939	1 998	2 278	2 528	2 789
OTHER INDUSTRIAL	445	451	454	456	466	472	479
ELECTRIC GENERATION	28	71	158	158	165	165	165
TOTAL END-USE DEMAND	2 299	2 402	2 552	2 612	2 909	3 164	3 433
EXISTING CAPACITY:							
Firm Sales	235	235	235	235	235	235	235
Firm Transportation	886	886	886	886	886	886	886
TOTAL TRANSMISSION	1 121	1 121	1 121	1 121	1 121	1 121	1 121
STORAGE	372	372	372	372	372	372	372
LNG STORAGE	522	522	522	522	522	522	522
TOTAL STORAGE	894	894	894	894	894	894	894
EXPANSIONS:							
PGT Direct	0	31	185	185	185	185	185
Northwest Direct	0	118	237	237	237	237	237
Total Expansions	0	149	422	422	422	422	422
TOTAL CAPACITY	2 015	2 164	2 437	2 437	2 437	2 437	2 437
TOTAL PEAK DAY DEFICIT	284	238	115	175	471	727	995

Source: ANG filing with respect to the AERCB's "Call for Information - Altamont and PGT Pipeline Projects", Proceeding 911586, "General Demand/Supply Information Requirements", Table 1-18.

The ANG Market Study concluded that even with the capacity expansion planned by PGT and Northwest Pipeline, the Pacific Northwest may experience significant peak day firm capacity deficits starting in the mid-1990s and continuing throughout the forecast period.

Competing Gas Supplies and Transportation Systems

ANG indicated that the Pacific Northwest is presently serviced with gas supplied from the Rocky Mountain areas and from the Western Canada Sedimentary Basin ("WCSB") via the ANG/PGT, Westcoast Energy Inc. ("Westcoast"), and Northwest Pipeline systems (reference Figure 3-1 for a map of the natural gas transmission pipelines serving the Pacific Northwest). ANG noted that with the completion of the Kern River Gas Transmission Company ("Kern River") facilities, Rocky Mountain supply will move into the California market, thereby creating an opportunity for Canadian gas to gain market share in the Pacific Northwest.

With respect to competing pipeline capacity into the Pacific Northwest, ANG identified the expansion proposals by Northwest Pipeline to increase its capacity at Huntingdon, B.C., by 250 MMcfd from the current 840 MMcfd, and from the Rocky Mountain area by 185 MMcfd from the current 580 MMcfd.

3.1.2 California

Total gas demand in the California market is forecast to increase from 5,500 MMcfd in 1992 to 7,750 MMcfd in 2011, or by 1.8 percent per year on an average annual basis (reference Table 3-4). California is the second largest gas consuming state in the U.S., consuming some 1.9 Tcf in 1990, or approximately 11 percent of total U.S. gas consumption.

PG&E, which serves northern and central California and which is the largest combined gas and electric utility in the U.S., accounted for approximately 833 Bcf or 45 percent of total 1990 statewide gas consumption. Southern California Gas Company ("SoCal Gas"), which serves southern California and which is the largest LDC in the U.S., consumed approximately 890 Bcf or 48 percent of total 1990 statewide gas consumption. The remaining 121 Bcf was consumed by SoCal Gas's two wholesale customers, San Diego Gas and Electric Company ("SDG&E") and the City of Long Beach, both of which own and operate gas distribution systems.

The California forecast reflects gas demand in the following market sectors: residential, commercial, industrial, cogeneration, enhanced oil recovery ("EOR"), UEG, natural gas vehicles ("NGVs"), and desalination facilities.

Overall, the ANG Market Study forecast steady growth in gas demand and hence, growth in the demand for interstate pipeline capacity. The following factors were identified as contributing to that growth:

- Regulatory initiatives at both the federal and state levels aimed at implementing new gas procurement rules for the LDCs and at developing a mechanism for brokering interstate pipeline capacity held by the LDCs. These regulatory initiatives are intended to further deregulate the gas industry, to make gas more competitive, and to increase the supply options available to California gas users;

- Environmental regulations which place a greater emphasis on the use of clean burning fuels, such as gas, particularly for electricity generation and for use in the transportation sector (i.e. NGVs); and

- Economic and demographic factors such as sustained growth in population, employment and personal incomes.

Figure 3-1
Natural Gas Pipelines Serving California and the Pacific Northwest

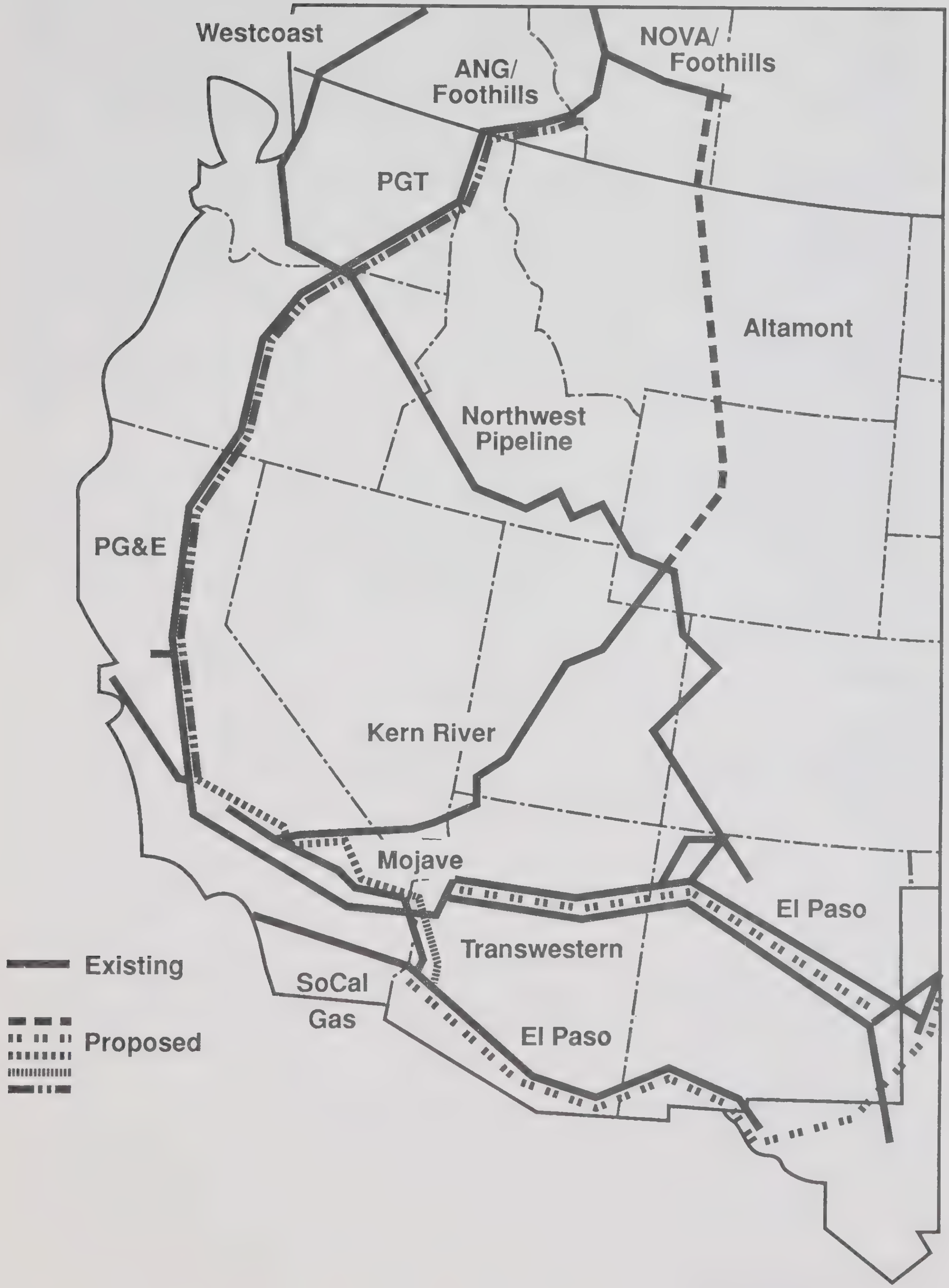

TABLE 3-4

CALIFORNIA NATURAL GAS DEMAND

(MMcfd)

NORTHERN CALIFORNIA	1992	1993	1994	1995	2000	2005	2011
CORE	830	843	849	850	907	978	1 084
NONCORE (a)	1 568	1 568	1 603	1 542	1 730	1 852	2 008
Commercial	4	4	4	4	4	4	4
Industrial	472	469	467	468	611	697	728
Cogeneration	178	213	249	263	272	279	287
EOR	177	220	201	198	218	213	244
UEG	731	656	677	604	619	652	738
Wholesale	6	6	5	5	6	7	7
NGV	1	2	7	12	31	38	43
DESALINATION	0	0	0	0	2	2	2
COMPANY USE & LAUF	72	72	74	72	80	86	94
TOTAL NORTHERN CALIFORNIA	2 471	2 485	2 533	2 476	2 750	2 956	3 231

SOUTHERN CALIFORNIA	1992	1993	1994	1995	2000	2005	2011
CORE	1 208	1 222	1 251	1 262	1 314	1 372	1 436
NONCORE (a)	1 749	1 880	1 938	2 014	2 355	2 543	2 841
Commercial	45	46	47	47	51	54	60
Industrial	226	251	266	287	325	328	320
Cogeneration	254	256	262	269	286	301	305
EOR	580	627	621	634	704	664	680
UEG	645	700	743	776	989	1 196	1 478
NGV	0	1	2	3	37	96	125
DESALINATION	3	26	26	26	27	30	30
COMPANY USE & LAUF	55	58	60	62	70	75	83
TOTAL SOUTHERN CALIFORNIA	3 016	3 188	3 278	3 367	3 802	4 116	4 515

STATEWIDE TOTAL	1992	1993	1994	1995	2000	2005	2011
CORE	2 038	2 065	2 100	2 112	2 221	2 350	2 520
NONCORE (a)	3 317	3 448	3 541	3 556	4 085	4 395	4 850
Commercial	48	49	50	51	54	58	64
Industrial	697	720	733	755	936	1 025	1 048
Cogeneration	432	469	511	532	558	580	593
EOR	757	847	822	832	922	877	924
UEG	1 376	1 356	1 420	1 380	1 608	1 848	2 214
Other	6	6	5	5	6	7	7
NGV	1	3	9	15	68	134	169
DESALINATION	3	26	26	26	29	31	31
COMPANY USE & LAUF	127	131	134	134	150	162	177
TOTAL CALIFORNIA	5 486	5 673	5 810	5 843	6 552	7 071	7 747

EOR - Enhanced Oil Recovery
UEG - Utility Electric Generation
NGV - Natural Gas Vehicles
LAUF - Lost and Unaccounted For

(a) Noncore demand in northern and southern California is the sum of the demand in the commercial, industrial, cogeneration, EOR and UEG market sectors.

Source: ANG filing with respect to the AERCB's "Call for Information - Altamont and PGT Pipeline Projects", Proceeding 911586, "General Demand/Supply Information Requirements", Tables 1-2, 1-4 and 1-6.

Northern California[1]

Total northern California gas demand is forecast to increase from 2,471 MMcfd in 1992 to 3,231 MMcfd by 2011, or by 1.4 percent per year on an average annual basis.

Northern California core market demand[2] (i.e. residential and commercial) is forecast to increase from 830 MMcfd in 1992 to 1,084 MMcfd in 2011, or by 1.4 percent per year on an average annual basis. The forecast reflects the forecast developed by PG&E and incorporated in the *1991 California Gas Report.*

The northern California non-core market demand (i.e. commercial, industrial, cogeneration, EOR, and UEG) is forecast to grow from 1,568 MMcfd in 1992 to 2,008 MMcfd in 2011, or by 1.3 percent per year on an average annual basis. The forecast reflects slower industrial growth as industrial customers leave the state because of stricter air quality regulations and other economic pressures. The forecast also reflects incremental gas usage resulting from stricter air quality controls and the phase-out of oil usage over a seven-year period commencing in 1996.

Cogeneration gas demand is forecast to increase from 178 MMcfd in 1992 to 287 MMcfd in 2011, or by 2.6 percent per year on an average annual basis, with most of the increase occurring in the 1992-96 period.

Gas demand in the California EOR market is served primarily by SoCal Gas, with the remainder served by PG&E. EOR gas demand, which is dependent upon the mix of fuels used in steam generation, includes gas transported to the EOR projects by the local gas utilities and indigenous or field gas. The ANG Market Study noted that, commencing in 1992, new interstate pipelines are expected to provide another source of gas supply to the EOR market thus "bypassing" the local utility systems[3]. Therefore, the total EOR gas demand comprises the sum of:

- utility-served requirements;
- field gas supply; and
- "bypass" gas provided directly by new interstate pipelines.

The ANG Market Study showed that demand for out-of-state gas in the EOR market is expected to increase as a result of the phase-out of field crude oil usage in the EOR market by 1996 owing to more stringent air quality regulations and to a decline in field gas usage as indigenous gas reservoirs are depleted.

In northern California, EOR gas demand is forecast to increase from 177 MMcfd in 1992 to 244 MMcfd in 2011, or by 2.4 percent per year on an average annual basis.

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1. Northern California defined as all areas served by PG&E, while southern California defined as all areas served by SoCal Gas and its wholesale customers (definitions taken from ANG's 14 February 1992 response to an information request made by Kern River during the AERCB's Call for Information into the PGT Expansion and Altamont pipeline proposals).

2. The study defined core and non-core markets as follows: "The "core" refers to residential and commercial markets, and that part of the industrial and electricity generation markets that purchases gas supplies from the utilities; the "non-core" market refers to that part of the industrial and electricity generation markets that purchases non-utility gas supplies in an inter-fuel competitive environment."

3. Bypassing is forecast to serve 49 MMcfd, or 28 percent of PG&E's EOR market, in 1992 increasing to 183 MMcfd, or 74 percent, by 2011.

UEG gas demand in northern California is based upon PG&E's submission to the *1991 California Gas Report* and reflects the assumptions made with respect to the amount of precipitation, water levels in the reservoirs and accordingly, the amount of hydroelectric generation that will occur. The ANG Market Study noted that, since 1987, hydroelectric generation in northern California has been substantially below normal, reflecting a prolonged drought, and that most of this shortfall has been met by increased gas-fired generation. UEG gas demand in northern California is forecast to increase from 731 MMcfd in 1992 to 738 MMcfd in 2011, or by only 0.1 percent per year on an average annual basis.

NGV gas demand in northern California is forecast to increase from 1 MMcfd in 1992 to 43 MMcfd in 2011, or by some 18 percent per year on an average annual basis, reflecting the establishment of utility NGV programs recently announced by the CPUC. These programs provide financial incentives for original equipment manufacturer ("OEM") purchases of NGVs, NGV conversions, and the construction of private gas refueling stations.

During the 1992-2011 forecast period, several gas-fired water desalination plants are expected to be constructed along the California coast. The ANG Market Study noted that these facilities are extremely energy intensive and would bolster California's water supply alternatives in the face of continuing severe drought conditions. Gas demand in this market sector is forecast to remain steady at 2.0 MMcfd starting in 1998.

Southern California

Total southern California gas demand is forecast to increase from 3,016 MMcfd in 1992 to 4,515 MMcfd by 2011, or by 2.0 percent per year on an average annual basis (refer to Table 3-4.)

Southern California's core market demand is forecast to increase from 1,208 MMcfd in 1992 to 1,436 MMcfd in 2011, or 0.9 percent per year on an average annual basis. This increase reflects, in part, an annual population growth rate of 1.2 percent which the ANG Market Study noted is double the U.S. average. Other factors identified in the study as affecting core market growth were:

- growth in commercial floor space;
- general growth in industrial activity;
- level of employment; and
- substitution of gas for fuel oil due to more stringent environmental restrictions, particularly in the heavily-polluted areas of southern California regulated by the South Coast Air Quality Management District.

The ANG Market Study suggested that those environmental restrictions will result in the phase-out of about 75 percent of current fuel oil usage in the South Coast Air Quality Management District by 1996 and result in an incremental gas demand of 93 MMcfd.

Southern California's cogeneration gas demand is forecast to increase from 254 MMcfd in 1992 to 305 MMcfd in 2011, or by 0.7 percent per year on an average annual basis. This growth reflects a continuation of favourable state and federal regulations and the resulting increased use of power generated by Qualifying Facilities[1] to supply the state's electrical requirements.

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1. "Qualifying Facility" as defined in accordance with the regulations issued under the authority of the U.S. *Public Utilities Regulatory Policies Act of 1978.*

Total southern California EOR gas demand is forecast to increase from 580 MMcfd in 1992 to 680 MMcfd in 2011, or 1.3 percent per year on an average annual basis. The ANG Market Study noted that the decreasing availability of field crude oil and field gas over the forecast period will result in increasing gas requirements from utility and bypass sources, with the latter satisfying most of this load. The study's EOR forecast is based upon SoCal Gas's submission to the *1991 California Gas Report*.

Southern California's UEG gas demand is forecasted to grow substantially from 645 MMcfd in 1992 to 1,476 MMcfd in 2011, or by 3.6 percent per year on an annual average basis.

Southern California's NGV gas demand is forecast to increase from 1 MMcfd in 1993 to 125 MMcfd in 2011. The forecasts of SoCal Gas and PG&E for NGV demand reflect the continued availability of financial incentives for OEM vehicles, the construction of private refueling stations, the expansion of fleet passenger car and private vehicle markets, as well as expansion of the utilities' own use of NGVs.

Demand for gas in the desalination market sector is forecasted to grow from 3 MMcfd in 1992 to 30 MMcfd in 2011. The forecast reflects the expected construction of four large desalination facilities in southern California (one at Santa Barbara, two in the San Diego area, and one at Huntington Beach).

Demand for Interstate Pipeline Capacity

The ANG Market Study indicated that, coupled with the assessment of gas demand in the California market, there is a need to assess pipeline capacity to serve that market. ANG's study used as a starting point the end-use requirements forecast for the California market (reference Tables 3-4 and 3-5). After allowing for California's in-state gas supplies, California's out-of-state gas supply requirement was forecast to increase from 5,051 MMcfd in 1992 to 7,361 MMcfd in 2011.

The ANG Market Study indicated that three additional factors were taken into consideration to properly determine the amount of pipeline capacity required to serve the California market. These factors were identified as follows:

- Core market capacity reservation, or the amount of capacity required by the utilities to serve core market customers who lack the means to access alternative energy supplies;

- Non-core market capacity reservations, or the amount of capacity required by non-core customers and/or their gas suppliers to allow them to participate in the competitive gas procurement market; and

- Pipeline capacity on the market at any given time waiting to be brokered (i.e. "frictional" capacity). The amount of frictional capacity is estimated to be one percent of the total available capacity.

After allowing for these three additional factors, California's total pipeline capacity requirements were forecast to increase from 5,942 MMcfd in 1992 to 8,570 MMcfd by 2011. The ANG Market Study concluded that California will be in a pipeline capacity deficit position for most of the forecast period, with the deficit expected to increase from 165 MMcfd in 1992 to 1,855 MMcfd by 2011.

ANG submitted that its analysis clearly demonstrated the need for additional pipeline capacity from Canada.

TABLE 3-5

TOTAL CALIFORNIA PIPELINE CAPACITY REQUIREMENTS

(MMcfd)

	1992	1993	1994	1995	2000	2005	2011
END-USE DEMAND (Adjusted)	5 487	5 673	5 811	5 843	6 553	7 071	7 746
LESS: CALIFORNIA SUPPLIES	436	384	384	413	443	441	385
INTERSTATE SUPPLY REQUIREMENTS	5 051	5 289	5 427	5 430	6 110	6 630	7 361
ADDITIONAL CAPACITY RESERVATIONS:							
Core Market	472	479	484	486	515	551	601
Noncore Market	386	400	411	412	473	508	560
Frictional	33	34	35	36	41	44	48
TOTAL CAPACITY REQUIREMENTS	5 942	6 203	6 358	6 363	7 139	7 733	8 570
AVAILABLE PIPELINE CAPACITY:							
El Paso	3 090	3 090	3 090	3 090	3 090	3 090	3 090
Transwestern	750	750	750	750	750	750	750
Kern River/Mojave	917	1 100	1 100	1 100	1 100	1 100	1 100
PGT	1 020	1 020	1 020	1 020	1 020	1 020	1 020
PGT Expansion	0	0	755 (a)	755	755	755	755
TOTAL PIPELINE CAPACITY	5 777	5 960	6 715	6 715	6 715	6 715	6 715
CAPACITY SURPLUS (DEFICIT)	(165)	(243)	357	352	(424)	(1 018)	(1 855)
SYSTEM-WIDE LOAD FACTOR (%)	88.3	89.4	81.9	82.0	91.5	98.8	109.1

(a) Assumes PG&E's take-away capacity in California available to deliver 250 MMcfd of the expansion volumes to northern California and 505 MMcfd to southern California.

Source: ANG filing with respect to the AERCB's "Call for Information - Altamont and PGT Pipeline Projects", Proceeding 911586, "General Demand/Supply Information Requirements", Table 1-8.

Competing Gas Supplies and Transportation Systems

ANG indicated that, at present, California is supplied with gas originating in the California, Permian, San Juan and Anadarko Basins, as well as with gas originating in the WCSB. ANG noted, however, that with the completion of the Kern River and Mojave Pipeline Company ("Mojave") pipeline systems, and with the expansions of the El Paso Natural Gas Company ("El Paso") and Transwestern Pipeline Company ("Transwestern") systems, additional deliveries will occur from the Rocky Mountain and San Juan Basins, with an offsetting decrease in deliveries from the Permian and Anadarko Basins (refer to Figure 3-1 for a map of the natural gas transmission pipelines serving California).

ANG believes that, as a result of the new pipelines and the underlying production and development economics, there will be a re-shuffling of market share and California will take its gas from the WCSB, the Rocky Mountain Basin, and the San Juan Basin coal seams, making the Permian Basin, the Anadarko Basin, and conventional sources in the San Juan Basin the marginal sources of supply.

With respect to competing pipeline capacity into the California market, ANG identified the following:

(a) El Paso Natural Gas Company

Existing: 1,210 MMcfd of firm and 200 MMcfd of interruptible capacity on the "south" system from the Anadarko, Permian, and San Juan Basins to SoCal Gas at the Arizona-California border. SoCal Gas's receipt capacity exactly matches the El Paso capacity.

1,140 MMcfd of firm capacity to PG&E and 540 MMcfd of firm capacity to SoCal Gas on the "north" system, from the San Juan, Anadarko, and Permian Basins to the Arizona/California border. PG&E's and SoCal Gas's aggregate receipt capacity exactly matches the El Paso capacity.

Expansion: Increase of 400 MMcfd on the "north" mainline, from the San Juan Basin to the Arizona-California border. The receipt capacity will be provided by the Mojave system (400 MMcfd).

(b) Transwestern Pipeline Company

Existing: 760 MMcfd of firm capacity from the Anadarko, Permian and San Juan Basins to SoCal Gas at the Arizona-California border. SoCal Gas's receipt capacity exactly matches the Transwestern capacity.

Expansion: Increase of 340 MMcfd on the mainline to California, plus interconnections with SoCal Gas, PG&E, and Mojave. Neither PG&E nor SoCal Gas has announced plans to increase its receipt capacity from the Transwestern interconnections.

(c) Kern River Gas Transmission Company

Initial: 700 MMcfd of firm capacity from the Rocky Mountains to southern California is nearing completion. SoCal Gas is reportedly considering constructing approximately 400 MMcfd of additional receipt capacity from the combined Kern River/Mojave project.

(d) Mojave Pipeline Company

Initial: 400 MMcfd of firm capacity from the Arizona-California border into southern California nearing completion. Gas originates in the San Juan Basin. SoCal Gas is considering constructing approximately 400 MMcfd of additional receipt capacity from the combined Kern River/Mojave project.

In addition to the aforementioned market study commissioned by ANG, PGT conducted an analysis of the economic and market feasibility of the ANG/Foothills (South B.C.)/PGT/PG&E expansion project using primarily the North American Regional Gas model. PGT used this model to examine the competitive environment confronting the expansion project, including an assessment of alternative gas supplies, alternative energy sources, and alternative pipeline systems into those markets.

ANG indicated that PGT's analysis revealed that if the growing California market was to sequence its gas supplies based on "net-forward" costs (i.e wellhead costs plus transportation cost), the most-likely ordering of gas supplies, from low to high-cost, would be as follows:

(a) tax-advantaged coalbed methane from the San Juan Basin;

(b) Canadian supply via the existing ANG/Foothills (South B.C.)/PGT/PG&E system;

(c) Canadian supply via the expanded ANG/Foothills (South B.C.)/PGT/PG&E system;

(d) Rocky Mountain supply via the Kern River system; and

(e) other supplies sourced from the U.S. southwest, including conventional supplies from the San Juan, Permian, and Anadarko Basins.

The PGT analysis showed that despite strong price competition from competing gas sources, Canadian gas supplies will capture and maintain markets given the relatively low cost of finding gas in the WCSB and the favourable economics of the ANG/Foothills (South B.C.)/PGT/PG&E transmission system.

3.2 Project-specific Markets

The 28 export shippers who have contracted for ANG expansion capacity represent major U.S. gas and electric utilities, Canadian producers and aggregators, and Canadian and U.S. gas marketers (reference Appendix II). The shippers are at various stages in finalizing their gas market arrangements and securing their Canadian and U.S. regulatory approvals (e.g. provincial removal permits, Board export authorizations, and U.S. Department of Energy / Office of Fossil Energy ("DOE/FE") import approvals).

In addition to the 28 export shippers, BC Gas Inc. ("BC Gas") has contracted for 141.6 $10^3m^3/d$ (5.0 MMcfd) of firm transportation service for off-line service to southeastern B.C.

Views of the Applicant

ANG argued that it has amply demonstrated the overall, long-term need for the expansion facilities, and noted that all of the gas to be transported by the expansion shippers will serve incremental markets in the U.S. Pacific Northwest and in California.

ANG indicated that the expansion shippers which intend to serve northern California markets will deliver the gas to the end-use markets located in PG&E's service territory. The expansion shippers who intend to serve southern California will deliver the gas to the service areas of SoCal Gas (i.e. deliveries to Southern California Edison Company ("SoCal Edison"), Burbank, Glendale and Pasadena) and SDG&E.

ANG submitted that, in the absence of more detailed, project-specific market information, the Board should have regard to the binding and unconditional firm transportation service contracts signed by the expansion shippers for the full expansion volume, and backed by financial assurances, as a clear indication of the existence of those markets.

ANG argued that, as pipeline companies move away from their traditional merchant function towards simply providing a transportation service, they are no longer directly involved in the marketing of gas. ANG submitted that, in respect of the expansion, it has experienced a similar change in its role, and that this has limited its ability to provide the Board with project-specific market evidence. ANG added that if it were forced to wait until such evidence is available to obtain Board approval of the expansion facilities, it would not be able to meet the scheduled in-service date of 1 November 1993. ANG expressed the belief that a delay beyond 1 November 1993 would result in the expansion shippers losing market opportunities.

ANG submitted that it is assured that the expansion facilities will be used at a reasonable level, and that the demand charges will be paid, through the executed, unconditional firm service transportation agreements and through the expansion shippers' compliance with ANG's financial assurance requirements. ANG argued that these firm transportation and financial assurance obligations, coupled with corresponding obligations on upstream and downstream pipeline systems, provide those expansion shippers with the necessary incentive to maximize their use of the contracted-for ANG expansion capacity.

ANG indicated that it currently has a queue for firm transportation service after its expansion comes on stream 1 November 1993. ANG noted that PGT similarly has a "log of firm transportation requests" which contains some 180 requests totalling 226.6 $10^6 m^3/d$ (8.0 Bcfd) of requested service.

ANG submitted that there is adequate time for the ANG expansion shippers to apply for their regulatory approvals (i.e. AERCB gas removal permit, NEB export authorization, and/or DOE/FE U.S. import approval) since the in-service date of the expansion project is not until 1 November 1993.

ANG cited the following additional reasons why many of the expansion shippers have not yet applied for their regulatory approvals:

- PGT's second open season[1] caused the original open season shippers to delay contract negotiations until the outcome was resolved and the new shippers, which had not initiated contract negotiations, were added to the expansion project.

- Buyers and sellers in the California market have delayed making long-term commitments until the regulatory uncertainties at both the state and U.S. federal levels have been cleared up.

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1. An "open season" is a period of time during which all parties or all requests are given equal consideration. In the context of transportation service, it refers to a period of time during which all requests for transportation service are accorded equal priority in the queue for service, with space divided in a pro rata basis. After the open season is over, requests are generally treated on a first-come, first-served basis.

- The business strategy of many producer/marketer shippers has been to develop a market relationship before commencing negotiations towards finalizing long-term contracts. In this regard, ANG noted that shippers are reluctant to file their regulatory applications until contract negotiations have been completed, as to do otherwise would undermine the shippers' competitive and negotiating positions.

ANG concluded that the strong demand for pipeline capacity, as highlighted by an over-subscribed expansion project and by unconditional firm service agreements executed with various types of shippers who must compete in those markets with all types of energy sources, "goes well beyond the results of any macro analysis that could be carried out by a third party".

ANG submitted that its proposed expansion will accord many shippers and Canadian gas suppliers their first direct access to new markets in the U.S. Pacific Northwest and in California. ANG therefore urged the Board to grant expeditious, unconditional approval of its facilities application thereby permitting those shippers to conclude their gas supply and gas sales contract negotiations and enabling Canadian gas producers to proceed with reserves and production development.

Views of Interested Parties

The Alberta Petroleum Marketing Commission ("APMC") submitted that the evidence shows that ANG's proposed expansion would provide enhanced access to U.S. gas markets. The APMC noted the absence of project-specific market evidence and ANG's reliance on its overall assessments of the Pacific Northwest and California markets to support the facilities expansion. The APMC also noted that the overall demand evidence was supplemented by no-out, long-term, firm service and project agreements. The APMC concluded that, "on an aggregate basis", the market demand appears to support the need for the applied-for facilities. The APMC expressed the belief that, if the Board does not require the project-specific market information to determine the economic feasibility of the expansion, then the Board could rely on those "other considerations" (i.e. executed, long-term, firm service agreements).

Amoco Canada Petroleum Company Ltd. ("Amoco") noted the absence of project-specific market information and executed gas sales contracts and accordingly, argued that there is currently insufficient market commitment to the ANG/Foothills (South B.C.)/PGT/PG&E expansion.

Czar Resources Ltd. ("Czar") noted that the *1991 California Gas Report* indicates that California will be in an over-supply position as a result of U.S. interstate pipeline expansions prior to the ANG/PGT expansion and, therefore, raises doubt as to the need for the applied-for ANG facilities. Czar recommended that the Board deny ANG's facilities application.

Foothills Pipe Lines Ltd. ("Foothills") submitted that associated contractual arrangements and regulatory approvals have sufficiently advanced to support the need for the ANG expansion facilities and therefore, their timely approval. Specifically, Foothills cited:

- ANG's evidence which demonstrates overall market need for the incremental pipeline capacity;

- support for the expansion project from Canadian gas producers, gas supply aggregators, gas marketers, and from U.S. end-use customers;

- the long-term, firm transportation service agreements executed by each of the expansion shippers with NOVA, ANG, and PGT;

- the U.S. Federal Energy Regulatory Commission's ("FERC's") issuance of a certificate to PGT authorizing the construction of PGT's incremental facilities; and

- the CPUC's issuance of a certificate to PG&E authorizing the construction of PG&E's incremental downstream facilities.

The Indicated Expansion Shippers, a group comprised of Chevron, NCMI, and Petro-Canada, along with Norcen Marketing Inc. (all four companies collectively referred to herein as "the IES") supported the ANG facilities application, noting that the expansion would meet the requirements of Alberta producers and marketers wishing to export additional gas into the California market.

Mobil Oil Canada ("Mobil") expressed concern that the Board had not received the best available evidence pertaining to markets and that the Board has been asked to deal with the application at a time when circumstances outside of its jurisdiction are changing. Specifically, Mobil expressed concern with respect to the following:

- the export markets to be served may, in fact, not be new incremental markets, thus displacing existing supplies from Canada;

- the overall California demand for Canadian gas, given the availability of alternative supplies that could be made available via the El Paso and Transwestern expansions and the new Kern River facilities;

- the overall California demand for Canadian gas, given the availability of U.S. coal seam gas and a U.S. federal tax credit which is intended to encourage its production; and

- the impact on the demand for Canadian gas in light of recent U.S. regulatory initiatives (e.g. the CPUC's decision regarding capacity brokering on the PG&E system).

Mobil recommended that the Board should either (i) convene a public hearing to properly determine the need for the ANG expansion or (ii) issue an order if it agreed that the proponents of the expansion should bear the risk of construction and operation of the expansion facilities by being prevented from passing the costs on to third parties upstream of the facilities through "tariffs (e.g. incremental tolls), statutory provisions (e.g. CPUC rules or orders), or prevailing contractual arrangements (e.g. aggregator netback pricing contracts)".

PGT submitted that the ANG expansion will provide an essential link for Canadian gas to the growing markets in the U.S. Pacific Northwest and California and that ANG's evidence clearly demonstrated the existence of those markets.

Poco, which has contracted to supply Canadian gas to Northwest Natural Gas and IGI Resources, Inc. ("IGI") in the U.S. Pacific Northwest, submitted that the ANG expansion is required and that unless this incremental supply of Canadian gas is made available to those markets soon, Northwest Natural Gas and IGI will be forced to procure their supply elsewhere, which would result in a lower market share for Canadian gas.

Summit Resources Ltd. ("Summit"), which has executed a gas purchase contract with Northwest Natural Gas and SDG&E, submitted that the long-term firm transportation service contracts executed by Northwest Natural Gas and SDG&E with ANG is sufficient evidence as to the shippers' commitment to the ANG expansion. Summit does not believe that the Board needs additional information to approve the ANG facilities application and, accordingly, recommended that the Board do so as soon as possible since access to those U.S. incremental markets is critical to Summit's continued growth.

Unigas, which has executed gas purchase contracts with Northwest Natural, IGI, and the Cities of Burbank, Glendale, and Pasadena, submitted that ANG has provided, through the execution of its long-term binding transportation service agreements, adequate assurances that the applied-for facilities will be utilized.

WGML, which has arranged to sell 1 465.6 10^3m^3 (51.7 MMcfd) to SoCal Gas, submitted that the ANG expansion will provide Canadian producers "with a desirable sale to an incremental market". WGML noted that its producer group has approved the export sale to SoCal Gas and that it has, therefore, obtained a finding of producer support on the basis of the approval. WGML argued that there is a long-term commitment to the ANG expansion and that it should receive expeditious Board approval.

Views of the Board

The Board has considered ANG's overall assessments of the Pacific Northwest and California markets and is satisfied that, for the purpose of assessing the need for the expansion facilities, ANG's forecasts are reasonable.

In arriving at this conclusion, the Board took into account the fact that the Pacific Northwest forecast reflects the Pacific Northwest LDCs' least cost plans and that the California forecast reflects the various forecasts prepared by the California gas and electric utilities and submitted as part of the *California Gas Report*, prepared annually by the CPUC.

Moreover, the Board is aware that ANG's forecast is but one of several that have been published and which also use the *1991 California Gas Report* as a starting point.

Although the details with respect to project-specific markets and contractual arrangements remain to be finalized by many of the expansion shippers, the Board concurs with ANG and some of the interested parties that, in the absence of this project-specific market and contractual information, it should consider the binding and unconditional firm service agreements as demonstrating the existence of those specific markets. In this regard, the Board notes that some expansion shippers have made significant progress towards finalizing their market and contractual arrangements and securing requisite regulatory approvals.

The Board finds that ANG's overall and project-specific market evidence, coupled with the existence of executed long-term, unconditional firm service transportation agreements on the ANG and PGT systems for the entire expansion volume, satisfactorily demonstrates the existence of long-term incremental market opportunities for Canadian gas in the Pacific Northwest and California markets and, thus, supports the need for the expansion facilities.

On the basis of the foregoing, the Board has decided not to condition any approval it might issue upon ANG demonstrating, prior to the commencement of construction, the existence of project-specific gas sales arrangements and related Canadian and U.S. regulatory approvals.

Chapter 4

Contractual Arrangements and Risk Allocation

4.1 Transportation Service and Project Agreements

In accordance with the existing transportation service arrangements, ANG provides firm transportation services to Alberta and Southern Gas Co. Ltd. ("A&S") and Westcoast Energy Inc. ("Westcoast") at Kingsgate, B.C. for 36.2 $10^6m^3/d$ (1,278.9 MMcfd). In addition, ANG provides firm transportation at Kingsgate for 6.8 $10^6m^3/d$ (240.0 MMcfd) through the incremental capacity resulting from the interconnection of the Foothills (South B.C.) and ANG facilities. ANG also provides transportation service for off-line sales into B.C.

In support of its facilities expansion, ANG has entered into long-term (i.e. 15 to 30 year) unconditional service agreements with each of the 28 export shippers who have subscribed for service on the PGT and PG&E pipeline expansions. ANG has contracted to deliver an incremental, annual average daily volume of 24 716.0 $10^3m^3/d$ (872.5 MMcfd) to the Kingsgate, B.C. export point. ANG has also entered into a service agreement with BC Gas for the delivery of 141.6 $10^3m^3/d$ (5.0 MMcfd) of gas into B.C. (reference Table 4-1).

The service agreements state, among other things, that the "shipper covenants that it will make timely arrangements for upstream and downstream transportation, gas supply and markets and all necessary governmental authorizations". Further, the shipper acknowledges that ANG is relying upon the covenant and agrees that "if any such arrangements or authorizations are not in place prior to the Service Availability Date, such will not affect the shipper's obligation to pay any demand charge, surcharge, or any other amount payable to the Company".

In addition, ANG has entered into a project agreement with each of the expansion shippers. The project agreement provides that ANG will waive the payment of any demand charges which would otherwise be payable between ANG's service availability date and the later of PGT's or PG&E's service availability dates. That is, ANG will waive the expansion shipper's obligations to pay demand charges if ANG's in-service date occurs prior to PGT's or PG&E's in-service date. No such waiver was provided for with respect to the upstream NOVA service availability date.

However, the waiving of the demand charge payment during the aforementioned period is provided on the condition that ANG is entitled to accumulate and capitalize in its rate base, subject to Board approval, an allowance for funds used during construction ("AFUDC") in relation to ANG's portion of the expansion project for that period.

The project agreement also provides that if either PGT's or PG&E's start of construction is delayed and if PGT or PG&E amends its service agreements with its shippers to provide for the right to terminate those agreements for that reason, then ANG agrees to concurrently provide the shipper the right to terminate its firm service agreement with ANG. The termination becomes effective on the date the shipper's service agreement with PGT or PG&E terminates.

4.2 Upstream and Downstream Transportation Arrangements

ANG noted that all of the ANG expansion shippers, or their gas suppliers, have either filed their transportation service requests or have executed their 15-year transportation service agreements with NOVA for service starting 1 November 1993. ANG further noted that NOVA anticipates

Table 4-1

Alberta Natural Gas Company Ltd.
Pipeline Expansion Shipper Volumes
Kingsgate, B.C.

	Term of Contract		Contracted Quantity					
Shipper	From	To	Annual (MMcfd)	Winter (MMcfd)	Summer (MMcfd)	Annual ($10^3m^3/d$)	Winter ($10^3m^3/d$)	Su (1[illegible]
I EXPORT								
CanWest Gas Supply Inc.	1/11/93	31/10/08	27.7			784.7		
Cascade Natural Gas Corp.	1/11/93	31/10/23		7.5			212.2	
Chevron Canada Resources	1/11/93	31/10/23	52.0			1 473.0		
City of Burbank	1/11/93	31/10/08	4.8			136.5		
City of Glendale	1/11/93	31/10/23	4.1			115.4		
City of Pasadena	1/11/93	31/10/23	4.1			115.4		
C.P. National Corporation	1/11/93	31/10/23		6.7			189.4	
DEKALB Energy Canada Ltd.	1/11/93	31/10/08	11.9			336.4		
IGI Resources, Inc.	1/11/93	31/10/13	7.0			198.3		
Norcen Energy Resources Limited	1/11/93	31/10/08	47.5			1 345.3		
North Canadian Marketing Inc.	1/11/93	31/10/08	19.8			560.5		
North Canadian Oils Limited	1/11/93	31/10/08	39.6			1 121.1		
Northern California Power Agency	1/11/93	31/10/08	5.5			157.0		
Northridge Alberta Gas Sales Ltd.	1/11/93	31/10/08	8.2			230.8		
Northwest Natural Gas Company	1/11/93	31/10/08		46.4	29.9		1 315.3	
Pan Alberta Gas Ltd.	1/11/93	31/10/23	59.4			1 681.6		
PanCanadian Petroleum Limited	1/11/93	31/10/08	40.7			1 154.0		
Pancontinental Oil, Ltd.	1/11/93	31/10/08	4.1			115.4		
Paramount Resources Ltd.	1/11/93	31/10/23	19.8			560.5		
Petro-Canada	1/11/93	31/10/08	19.8			560.5		
Sacramento Municipal Utility District	1/11/93	31/10/23	12.2			346.2		
Shell Canada Limited	1/11/93	31/10/08	27.7			784.7		
San Diego Gas & Electric Company	1/11/93	31/10/08	53.0			1 502.2		
Southern California Edison	1/11/93	31/10/08	203.7			5 770.2		
Suncor Inc.	1/11/93	31/10/08	40.7			1 154.7		
Vector Energy Inc.	1/11/93	31/10/08	16.9			478.0		
Washington Energy Exploration, Inc.	1/11/93	31/10/08		65.4	44.7		1 851.4	1 [illegible]
Washington Water Power	1/11/93	31/10/23		54.4	29.8		1 541.9	[illegible]
TOTAL EXPORT VOLUMES			730.2	180.4	104.4	20 682.4	5 110.2	2 9[illegible]
II DOMESTIC								
BC Gas Inc. (1)	1/11/93	31/10/08	5.0			141.6		
TOTAL EXPORT AND DOMESTIC VOLUMES			735.2	180.4	104.4	20 824.0	5 110.2	2 9[illegible]

(1) For the receipt of gas near Coleman, Alberta and the delivery of gas at various points of delivery on the ANG system.

filing its 1992/93 annual plan, which will cover the facilities required to accommodate the expansion project, with the AERCB in late May 1992.

Downstream, each of the expansion shippers has executed an unconditional firm transportation service agreement with PGT. These agreements are generally for a term of thirty years. ANG noted that these are long-term, firm and irrevocable commitments to PGT pipeline capacity.

Similarly, where applicable, each of the expansion shippers has either executed a firm transportation service agreement with PG&E, or has commenced negotiations to that end.

On 4 October 1991, Northwest Pipeline filed an amended application with the FERC for a certificate of public convenience and necessity. Although its facilities application is still pending before the FERC, Northwest Pipeline expects to start construction in June 1992 and to have its facilities in service by 1 April 1993. Northwest Pipeline has applied for additional capacity to provide 534 MMcfd of incremental firm deliveries, including the delivery of additional Canadian gas from Huntingdon, B.C. to PGT at Stanfield, Oregon, and deliveries to C.P. National and Northwest Natural Gas related to the PGT expansion.

On 1 August 1991, the FERC issued PGT a final certificate. This certificate provided for, among other things:

- rates based on incremental cost allocation;
- acceptance of an escalated capital cost estimate of $808.6 million (U.S.); and
- a prohibition against the commencement of construction until PGT has demonstrated that the expansion shippers will not be discriminated against on PG&E.

On 24 October 1991, however, the FERC removed this prohibition against construction and instead reduced PGT's rate of return on equity from 12.5 to 10.13 percent until such time as PGT presents evidence to the effect that the expansion shippers are not being discriminated against on either the PGT or PG&E pipeline systems. The certificate, as amended by the FERC on 24 October 1991, enables PGT to begin construction by January 1992, as scheduled. Construction of the PGT expansion is currently underway.

On 27 December 1990, the CPUC issued to PG&E a certificate for its California facilities expansion and certified the "Final Environmental Impact Report" pursuant to the *California Environmental Quality Act*. The certificate decision provided for, among other things:

- a capital cost cap for the facilities of $696 million (U.S.);
- the establishment of incremental cost allocation as a policy thus deferring actual cost allocation and rate design until the first general rate case for the PG&E expansion; and
- the filing with the CPUC of PG&E's transportation service contracts prior to the commencement of construction.

Construction of the PG&E facilities commenced in December 1991 with preparations to install pipe under three Sacramento Delta waterways east of Oakley, California.

ANG noted that SoCal Gas might require some reinforcements to its existing system and if that were the case, ANG expected SoCal Gas to commence construction in 1993 to meet the 1 November 1993 in-service date. SoCal Gas's facilities require CPUC approval.

4.3 The ANG/Foothills Agreement

ANG and Foothills have reached agreement with respect to the participation of both pipeline companies in the construction and ownership of the additional facilities in southeastern B.C. In accordance with that agreement, ANG is responsible for the design, construction, and operation of the expansion facilities. ANG will own the compression facilities and Foothills (South B.C.) will own the pipeline sections connecting its existing pipeline segments[1].

In this regard, ANG and Foothills have executed a precedent agreement, dated 9 May 1990, in accordance with which ANG will enter into a firm service agreement with Foothills calling for Foothills to provide transportation service to ANG for the expansion shippers. ANG noted that this firm service agreement will be in the form of a T-1 transportation agreement as contained in Foothills' gas transportation tariff. ANG indicated that, in turn, Foothills (South B.C.) will execute a firm service agreement with ANG in accordance with which ANG will provide compression and 5.5 km of pipe to Foothills (South B.C.) which it requires to provide transportation service to the expansion shippers. ANG noted that this latter firm service agreement will be in the form of an FS-1 Service Agreement.

ANG submitted that it has not yet executed the firm service agreement with Foothills but expects to do so shortly. ANG, which undertook to file a copy of the final agreement, once executed, submitted that the Board should not delay consideration of its facilities application pending execution of the firm service agreement. ANG noted that although the final agreement has not been filed, all of the material evidence, including information on the tolls and terms of service, has either been filed in the GHW-2-91 proceeding or is reflected in the tariffs of ANG and Foothills.

ANG indicated that Foothills will charge ANG an allocated share of Foothills' costs of service[2] based on contract quantity and distance in accordance with the Foothills' Board-approved tariff.

ANG indicated that its cost of service will therefore consist of the following:

- ANG's operating and maintenance expenses;
- return, depreciation, and income taxes related to ANG's facility investment;
- the billings from Foothills covering transportation service provided by Foothills to ANG on the Foothills (South B.C.) segments for the ANG expansion volumes; and
- deductions for interruptible revenues, special service revenues such as small off-line deliveries and revenues received from Foothills (South B.C.) for transportation and operating service provided by ANG to Foothills (South B.C.)

ANG added that these costs are used to calculate its tolls and that these same tolls are charged to both existing and expansion shippers.

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1. As noted in subsection 1.2 of this report, the Foothills (South B.C.) loops have already been certificated under the *Northern Pipeline Act*.

2. Foothills' cost of service will consist of the following:
   - return, depreciation, and income taxes relating to the Foothills (South B.C.) system;
   - operating and maintenance expenses billed to Foothills (South B.C.) by ANG, as agents for Foothills (South B.C.), relating to the Foothills (South B.C.) system, plus any taxes and other government assessments apart from income taxes relating to the Foothills (South B.C.) system;
   - all tolls paid by Foothills (South B.C.) for transportation service on the ANG system consisting of compressor service and short hauls on the ANG-owned pipeline loops; and
   - an allocable share of Foothills' administrative charge.

4.4 Risk Allocation

In response to the various "at risk" proposals put forth in the hearing, ANG submitted that "since the traditional style of market and supply evidence has been replaced with a more appropriate form of evidence for this proceeding (i.e. executed long-term, unconditional service agreements), there was no need for any related shifting of risk to ANG from its shippers".

ANG indicated that it timed the filing of its facilities application in accordance with the requests for service of the expansion shippers and that those requests did not envisage putting ANG at financial risks of the type being proposed by certain intervenors. ANG noted that, should it be required to bear those risks, it would review its options, which could include applying for an offsetting increase in its rate of return.

ANG argued that it has taken appropriate measures to minimize the risk of shipper default and the possibility of under-utilized facilities and that, therefore, those risks should remain with the shippers in accordance with their contracted obligations. ANG added that the potential risks are minimized by the existence of a queue for ANG service and by the fact that the PGT expansion was significantly over-subscribed in two open seasons.

ANG indicated that it is not prepared to waive the operation of Clause 10 of the Service Agreement[1] in the event the upstream NOVA transportation facilities are not in place by ANG's "Service Availability Date". ANG argued that it had been clear from the outset that it was the obligation of the expansion shippers to arrange for upstream and downstream transportation as well as gas supply and markets. ANG further argued that these are shipper responsibilities associated with any typical pipeline expansion and that it would not agree to the waiver and accept the transfer of that obligation from its shippers.

ANG further noted that it is not a shipper on the NOVA system and it is therefore not responsible for contracting for NOVA capacity. ANG submitted that it is the gas suppliers or shippers who require NOVA service and who should, therefore, be entirely responsible and accept the risk for contracting that capacity. In this regard, ANG noted that only one of the expansion shippers had failed to execute a firm transportation service agreement with NOVA by the 1 November 1991 deadline for capacity for the 1993-94 contract year.

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1. Clause 10 provides that if the upstream transportation arrangements are not in place prior to the "Service Availability Date", the shipper will nevertheless be obligated to pay the ANG demand charges. In other words, the agreements do not expressly provide for a delay in the implementation of demand charges due to the unavailability of upstream facilities.

   The specific wording of Clause 10 is as follows:

   "Shipper covenants that it will make timely arrangements for upstream and downstream transportation, gas supply and markets and all necessary governmental authorizations and that it will advise the upstream and downstream transporters of the receipt and delivery points under this Agreement.

   Shipper acknowledges and agrees with Company that Company is relying upon the covenant contained in this clause and agrees that if any such arrangements or authorizations are not in place prior to the Service Availability Date, such will not affect the Shipper's obligation to pay any demand charge, surcharge, or any other amount payable to Company."

Given the existence of the long-term, binding transportation service agreements, ANG did not envisage any circumstances under which there would be a need to downsize or phase in its facilities expansion. ANG argued that, given the substantial regulatory progress made to date with respect to the downstream U.S. facilities, any material change in its facilities design could result in additional costs and project delays and result in increased costs and tolls for its shippers.

ANG indicated that, subject to Board approval, it intends to accumulate AFUDC charges in a deferral account and to charge those costs to the rate base once its expansion is placed in service.

Views of Interested Parties

The "at risk" proposals put forth by the various interested parties can be summarized as follows:

- That ANG be required to bear a greater share of the risk in the event a shipper defaults than would have been the case had a more traditional review of the facilities application been conducted on the basis of overall and project-specific supply and market information.

- That ANG be required to bear the fixed-cost risk if it proceeds with its facilities expansion before all contractual arrangements and regulatory approvals have been finalized.

- That ANG be required to bear all or part of the risk associated with any potential delays in the upstream NOVA service availability to ANG (i.e. that ANG be prevented from collecting demand charges until all related upstream and downstream expansion facilities are in place).

Amoco expressed concern regarding the size of the California market and noted the fact that too much additional pipeline capacity into California for Canadian gas would result in under-utilized pipeline capacity, the cost of which would have to be borne by all users of the system. Amoco noted the absence of project-specific market information and executed gas sales contracts and, accordingly, argued that there is currently insufficient market commitment to the ANG/Foothills (South B.C.)/PGT/PG&E expansion. Amoco believes that this lack of commitment increases the risk of constructing excess capacity and, accordingly, of existing shippers bearing a significant portion of the associated excess costs. Amoco submitted that the current uncertainties with respect to PG&E's future gas purchases and the future role A&S will play in providing gas to California directly affect how existing PGT, PG&E, ANG and Foothills capacity will be allocated and utilized in the future.

The APMC indicated that it continues to believe that existing tollpayers should not have to absorb the costs resulting from another shipper defaulting on its obligations (i.e. they should not have to incur any greater risk as a result of defaulting shippers). Therefore, the APMC believes that service agreements which include market or regulatory outs are inappropriate. The APMC was satisfied that there are no unacceptable market or regulatory-out clauses in the service agreements supporting the ANG facilities expansion.

The APMC noted that, while ANG has relied on its overall assessments of the Pacific Northwest and California markets, the incremental pipeline capacity proposals before the FERC and the Board to supply those markets exceeds their projected long-term requirements. The APMC believes that ANG should bear a greater risk of shipper defaulting in light of ANG's decision to request an expedited review of its facilities application and its request that the Board place increased reliance upon the overall, rather than upon the project-specific, market assessments.

Therefore, the APMC proposed that, should an expansion shipper default with respect to its demand charge obligation, "the NEB should consider whether ANG should first seek recourse

from the defaulting shipper to the fullest extent possible, and then assume the residual liability for the recovery of costs associated with shipper default".

The APMC believes that, in the event an expansion shipper withdraws its request for service prior to the commencement of construction, ANG should first attempt to allocate the capacity to a replacement shipper in accordance with a Board-approved procedure. Failing that, the APMC believes that ANG should be required to either downsize the expansion accordingly, or be placed at full risk for the cost recovery associated with the unsubscribed facilities. The APMC did not believe that the other shippers should bear the costs associated with the system under-utilization.

The APMC believes that ANG should have the responsibility for coordinating the in-service date of its expansion with the in-service dates of the upstream and downstream expansions.

CanWest submitted that the ANG unconditional, firm service agreements represent substantial commitments by the shippers to the marketplace and, therefore, recommended that the Board issue an unconditional order approving ANG's facilities application so that gas deliveries could commence starting 1 November 1993.

Chevron expressed concern with respect to the terms and conditions contained in both the ANG/Foothills and ANG/Foothills (South B.C.) agreements and, in particular, how the fees to be charged by Foothills to ANG were to be structured and levied. Chevron submitted that, since it had not received adequate information regarding the aforementioned fees or received any assurance from ANG that it would provide those agreements at a later date, the Board should direct ANG to:

- execute and file, in the GHW-2-91 proceedings, all agreements with Foothills and Foothills (South B.C.) relating to ANG's expansion project;
- file cost of service information upon which the tolls for the expansion facilities will be calculated, showing specific dollar amounts; and
- provide all shippers with an opportunity to comment on such agreements and cost of service information prior to approving the subject facilities application.

Chevron found the absence of a commitment to coordinate the in-service dates of the ANG, PGT, and PG&E expansions with the in-service date of the NOVA expansion to be "illogical". Chevron noted that, while efforts would be made to regularly review construction progress and to update the shippers, those measures do not ensure coordination of a common in-service date for all associated facilities or give those shippers any remedy in the event there is a delay in construction either on the ANG system or on the associated upstream or downstream systems.

Chevron noted that while Clause 5 of the project agreements waives the requirement to pay demand charges commencing from ANG's service availability date until PGT's and PG&E's service availability dates, no similar provision is provided with respect to the NOVA upstream capacity. Chevron indicated that the result is that the expansion shippers would be required to pay demand charges when the downstream facilities become available even if the upstream NOVA capacity is unavailable. Chevron noted that it had asked ANG to rectify the situation through contractual amendments but that ANG had declined to do so.

Chevron recommended that the Board condition any certificate or order so that:

> "ANG is prohibited from requiring payment of any demand charges that may otherwise be payable until such time as the last pipeline expansion facility supporting the ANG expansion project is connected and able to provide service and

all facilities involved in or supporting the ANG expansion project are able to receive, transport and deliver the natural gas volumes as per the shippers' volume contained within the firm service transportation agreement."

SoCal Edison submitted that the commitment to the ANG expansion has been demonstrated by the shippers' willingness to execute unconditional, firm transportation service contracts for the full incremental capacity and that those contracts provide "tremendous incentive" for those shippers to continue to use those facilities over the long term. SoCal Edison noted that this is enforced by the fact that those same shippers have similarly made long-term commitments to upstream and downstream capacity. However, SoCal Edison noted that there is a need to balance the risk between ANG and its shippers and, accordingly, recommended that the Board's order include an "at risk" condition to protect the expansion shippers "given the non-traditional type of review that has occurred here."

The IES expressed concern regarding the coordination of the start-up dates of the upstream (i.e. NOVA) and downstream (i.e. PGT and PG&E) facility expansions with the start-up date of the ANG facility expansion.

With respect to the need to coordinate with downstream facilities, the IES noted that several expansion shippers have entered into project agreements which defer demand charge obligations (i.e. risk) until such time as the expanded downstream PGT and PG&E facilities are in place. They noted, however, that during such period when demand charges are waived, ANG would be entitled to accumulate and capitalize AFUDC in its rate base, subject to Board approval. The IES further noted that this would ultimately be reflected in ANG's cost of service.

The IES also noted that the service agreements between ANG and the expansion shippers do not provide for a delay in implementing demand charge obligations due to the unavailability of upstream transportation capacity (i.e. NOVA). While acknowledging statements by ANG that voluntary efforts were being made to coordinate the completion of the NOVA facilities with those to be constructed by ANG, PGT and PG&E, they consider it essential that strict coordination take place between NOVA, ANG, PGT and PG&E in order to minimize, or to eliminate, the risk of exposure to AFUDC and demand charge obligations.

The IES recommended that the Board include a condition in the order or certificate which would provide that "no demand charges be collected or no AFUDC charged through the tolls until after a specific review of the circumstances by the Board at a subsequent ANG tolls hearing".

The IES had requested a copy of the contractual arrangement between ANG and Foothills (South B.C.) associated with the transportation on the proposed ANG expansion. They noted that the agreement had not been provided and argued that the actual executed document between ANG and Foothills should be filed upon all tollpayers who would then be given the opportunity to comment "as part of the tolls hearing considering this expansion"

The IES indicated that they are specifically concerned that there be no duplication of unnecessary expenses reflected in the cost of service (e.g. rate of return, depreciation, and operation and maintenance expenses).

The Independent Petroleum Association of Canada ("IPAC") noted ANG's position that the existence of executed, unconditional contractual commitments between ANG and its expansion shippers clearly demonstrated "the need for the facilities and the willingness of the shippers to commit to the project through the payment of all applicable rates and charges commencing on the service availability date". IPAC submitted that while "this may be the first time the Board has been provided with such unconditional contractual commitments in support of an application for new facilities", it was concerned that the existing and future ANG tollpayers may be forced to

bear the financial risk associated with poor coordination of in-service dates of the ANG expansion capacity with those of the connecting upstream and downstream pipeline system (i.e. NOVA, PGT and PG&E).

IPAC submitted that, while ANG is prepared to waive demand charge obligations with respect to downstream capacity availability problems, ANG "expected its pre-service availability date costs (i.e. allowance for funds used during construction) to accumulate and capitalize in its rate base", subject to Board approval, during the waiver period. IPAC believes that it is inappropriate for ANG to expect prospective shippers to waive their future right to question the appropriateness of ANG earning AFUDC in these circumstances. Similarly, IPAC believes that it is inappropriate for existing shippers to be asked to pay tolls which reflect the recovery of AFUDC which is the result of poor facility in-service coordination among ANG, PGT and PG&E. IPAC recommended that the Board should determine the appropriateness of whether ANG should be seeking this kind of waiver from the expansion shippers through the Project Agreements.

IPAC noted that NOVA has advised its shippers that:

- PGT participants would not achieve their anticipated 1 November 1993 in-service date unless NOVA was secured for its liabilities associated with the financial commitments required in advance of the AERCB facility approvals;
- NOVA shippers requesting delivery to the PGT system had until 1 November 1991 to return executed NOVA transportation service agreements; and
- NOVA would review its financial security requirements with its shippers and would advise those shippers who had executed transportation service agreements by 1 November 1991 of NOVA's financial security requirements.

IPAC recommended that ANG be directed to review its facilities design after 1 January 1992 to reflect the actual number of shippers who elected to financially backstop NOVA's expansion. In the alternative, IPAC recommended that ANG should be prepared to accept the risk associated with any under-utilized facilities during the period NOVA is unable to provide service for those ANG shippers who may elect not to provide NOVA with appropriate financial assurances commencing 1 January 1992.

IPAC, while not recommending that the Board's approval be made conditional upon ANG demonstrating that all regulatory approvals have been granted and that all contractual arrangements have been executed, recommended that the Board advise ANG that, if ANG proceeded with its expansion before having secured those regulatory approvals and contractual arrangements, then ANG will have accepted the fixed-cost risk for its own account and not for the account of the other shippers.

Paramount recommended that the Board not condition its approval upon receipt by the expansion shippers of their Part VI approvals, for the following reasons:

- the facilities are supported by executed firm service agreements which provide ANG with financial assurances;
- capital expenditure for the ANG portion of the total expansion project is relatively modest;
- the downstream PGT and PG&E facilities have already been approved and contracted for; and
- the Board's own findings point to ample Canadian gas supplies to satisfy future domestic requirements, existing export commitments, and the export projects underpinning the subject ANG facilities expansion.

PGT submitted that, along with PG&E, it is the sponsor and proponent of the PGT/PG&E expansion project which, in conjunction with the proposed ANG and Foothills expansion will

provide new pipeline capacity into the U.S. Pacific Northwest and California markets for Canadian-sourced gas. PGT indicated that it undertook the expansion project since it believes that the additional capacity would be beneficial to the Canadian gas industry and to the gas consumers in the U.S. Pacific Northwest and California markets and that the expansion project offered the most direct and economical means of ensuring that.

PGT noted that the expansion project has 28 fully-contracted shippers who have executed firm, binding transportation service agreements with PGT which will accord many of those shippers their first direct access to the U.S. Pacific Northwest and California markets.

PGT submitted that on 27 December 1990 the CPUC authorized the construction and operation of the PG&E portion of the expansion project within California and that, on 1 August 1991, the FERC authorized the construction and operation of the PGT inter-state facilities. Both PG&E and PGT have accepted their certificates from the CPUC and the FERC, respectively.

PGT indicated that it and PG&E have commenced a two-year construction program aimed at having the facilities in service by 1 November 1993 as required by the expansion shippers. PGT submitted that in order to meet the 1 November 1993 in-service date, and to provide the expansion shippers with "some degree of market certainty", it was necessary to commence construction of the downstream U.S. facilities before final Board consideration of the ANG facilities application.

SDG&E submitted that ANG and any defaulting shipper should be at risk with respect to unrecovered demand charges and that ANG should not be permitted to reallocate those costs to the other users of the system. SDG&E concluded that in such an event the Board need not insist on the filing of long-term gas sales and purchase contracts and project-specific gas supply and gas market information. SDG&E noted that this "at risk" condition has been used by the FERC in certificating the PGT expansion facilities. SDG&E noted that, in doing so, the FERC exercised its discretion to avoid involving itself in a "formalistic determination of need" and thus avoided "the enormous expense and delay associated with litigation of the need issue". SDG&E encouraged "the Board to exercise its discretion in approving the ANG expansion facilities in such a way as to complement the new and evolving approach to pipeline certification adopted by the FERC in the PGT docket".

Views of the Board

With regard to Chevron's request that ANG file the cost of service information upon which the expansion tolls will be calculated, the Board concurs with ANG that this information can be found in the evidence filed in the subject proceeding or in the ANG and Foothills tariffs. Therefore, the Board will not direct ANG to file additional cost of service information.

With respect to Chevron's request that ANG be directed to file all executed final transportation agreements with Foothills and Foothills (South B.C.) relating to the facilities expansion, the Board believes that these should be filed prior to the commencement of construction. Therefore, the Board has decided to condition any approval it might issue to this effect.

The Board believes that, if under-utilization occurs and results in the non-recovery of demand charges, these charges should be accumulated in a demand charge deferral account and be brought forward by ANG for disposition in a future toll proceeding. At that time, the Board will examine the circumstances which resulted in the non-recovery and determine what portion, if any, should be borne by ANG or be recovered from ANG's existing and expansion shippers. When considering the disposition of deferral account balances, the onus will be on ANG to demonstrate that its actions were prudently taken and were, therefore, in the best interests of its tollpayers.

The Board hereby directs ANG to establish a separate demand charge deferral account with respect to any unrecovered demand charges associated with the expansion shippers underpinning the subject facilities expansion.

The Board is satisfied that ANG is taking reasonable steps to promote the coordination of the various in-service dates associated with the upstream and downstream pipeline facilities. The Board accepts ANG's argument that in executing the ANG service agreements, the shippers acknowledged their responsibility for arranging their upstream NOVA transportation. The Board agrees with ANG's position that ANG is not a shipper on the NOVA system and that it is therefore the responsibility of the gas suppliers or the ANG shippers to contract for, and accept, the risk associated with that upstream capacity.

Similarly, the Board notes that all but one of the expansion shippers have contracted for NOVA capacity. The Board believes that there is a reasonable expectation that, given the existence of these executed NOVA service agreements, the importance which Canadian gas producers attach to these new markets, and the pipeline companies' undertaking to coordinate their planning activities, the ANG and NOVA service availability dates will match to the extent practicable.

Therefore, the Board will not direct ANG to waive the operation of Clause 10 of the ANG Service Agreement in the event the NOVA facilities are not in place by ANG's service availability date.

With respect to the question of whether ANG should be allowed to collect AFUDC in the event the service availability dates for PGT and/or PG&E lag behind that of ANG, it is the Board's expectation that ANG will take all reasonable steps to avoid such an occurrence. The Board notes that, should such an event transpire, the matter could be brought forward on a complaint basis for resolution by the Board under Part IV of the Act. In considering any request to review the appropriateness of AFUDC charges incurred, the Board would take into account the actions that were taken by ANG to mitigate the possibility of incurring such costs.

The Board has not been persuaded that there is a need to condition any approval it might issue upon ANG bearing more or all of the risk associated with a shipper defaulting and with the consequent non-recovery of demand charges, bearing in mind that the issue of risk associated with unrecovered demand charges can be resolved at a future Part IV proceeding.

However, the Board has decided to condition any approval it might issue upon ANG demonstrating, prior to the commencement of construction, that all requisite U.S. regulatory approvals have been granted in respect of any necessary downstream transportation facilities and transportation services.

Chapter 5
Facilities

5.1 Design

ANG stated in its application that the south B.C. expansion facilities were designed to meet incremental delivery requirements at Kingsgate of approximately 24.7 $10^6m^3/d$ (872 MMcfd) annual average flow, 23.6 $10^6m^3/d$ (834 MMcfd) summer seasonal and July mean day flow, and 25.8 $10^6m^3/d$ (910 MMcfd) winter seasonal flow.

ANG stated further that, in order to determine the most appropriate method of handling the incremental gas flows, various combinations of pipeline and compression additions were reviewed.

ANG submitted that the design chosen by itself and Foothills (South B.C.) for the proposed pipeline expansion (as described in subsections 1.1 and 1.2 of this report) was determined on a lowest cost of service basis, considering the proposed total flow volumes. ANG noted that in addition to considering the effect of capital expenditures on cost of service, AFUDC, fuel cost, operations and maintenance, depreciation, and taxes were also taken into account in the calculations.

Views of the Board

The Board, having reviewed the application together with follow-up design information provided by ANG in response to Board information requests, is satisfied that ANG and Foothills (South B.C.) selected the optimum design to meet the incremental delivery requirements at Kingsgate.

5.2 Capital Cost Estimate

ANG provided capital cost estimates of $81.8 million for the proposed expansion of its own facilities and $104.7 million for the companion Foothills (South B.C.) expansion facilities (both in 1990 dollars). Breakdowns of these cost estimates are presented in Tables 5-1 and 5-2.

The CPA submitted that the proposed costs for the "non-installation" components of the ANG cost estimate (i.e. Project Management, Contingency, Overhead, and AFUDC) were excessive and should be reviewed by the Board. In support of this contention, the CPA pointed to recent facilities cost estimates filed with the Board by TransCanada PipeLines Limited ("TransCanada") and Westcoast and the comparatively low non-installation cost projections contained therein.

The CPA recommended that if, upon review, the Board determined the proposed costs to be excessive, the Board should deny the applied-for amounts. The CPA further suggested that the Board should then establish amounts that it considers to be appropriate, and invite ANG to show cause why those amounts should not be the costs that the Board approves.

The CPA acknowledged that it was not in a position to make specific recommendations as to what should be the "appropriate" cost levels. However, the CPA did suggest that ANG's provision for Project Management was excessive by about $2,000,000 and that the allowance for Contingency should be cut by about half.

Table 5-1

Summary of Capital Cost Estimate
for ANG Expansion Facilities

(All costs in thousands of 1990 dollars)

Materials	$41,940
Compressor Units	24,060
Pipe, Valves & Fittings	4,250
Coatings & Coverings	300
Other Materials	13,330
Installation	16,720
Project Management	6,590
Engineering	3,420
Supervision & Administration	1,000
Regulatory	360
Project Development	1,030
Environment	30
Procurement	320
Inspection	430
Other Costs	470
Insurance	320
ANG Labour	150
Subtotal	65,720
Contingency	6,560
Subtotal	72,280
Overhead	1,080
Subtotal	73,360
AFUDC	8,400
Total	$81,760

Table 5-2

Summary of Capital Cost Estimate for Companion Foothills (South B.C.) Expansion Facilities

(All costs in thousands of 1990 dollars)

Materials	$32,930
Pipe, Valves & Fittings	27,730
Pipe Coating	5170
Other Materials	30
Installation	47,510
Project Management	7,250
Engineering	2,150
ANG Supervision & Administration	1,030
Regulatory	180
Project Development	1,030
Foothills Administration	1,300
Environment	330
Land	100
Procurement	130
Inspection	1,000
Other Costs	3,340
Land	350
Gas Loss	400
NPA Surveillance	2,100
Insurance	490
Subtotal	91,030
Contingency	7,420
Subtotal	98,450
Overhead	1,480
Subtotal	99,930
AFUDC	4,730
Total	$104,660

ANG replied that all of the direct and indirect cost estimates in the application are reasonable and consistent with past practice, and are not directly comparable to other pipeline projects associated with different facts and circumstances.

The five main elements of the CPA's argument respecting the magnitude of the cost estimate are described below, followed in each case by a summation of ANG's reply comments.

(i) Engineering

In response to an information request from the CPA, ANG reported that about 14.4 percent ($493,000) of the estimated engineering costs for its own expansion ($3,420,000) and 38.0 percent ($818,000) of the estimated engineering costs for the Foothills (South B.C.) expansion ($2,150,000) had been spent to date. The CPA questioned whether 85.6 percent of ANG's engineering costs and 76.5 percent of the overall engineering costs remained, given that "ANG has carried out extensive engineering design work in the preparation of the application".

ANG argued that, contrary to the CPA's suggestion that extensive engineering work has already been done, the bulk of detailed design and engineering is planned for 1992. ANG asserted that the engineering design has advanced only to the stage needed to prepare regulatory applications and to order critical long delivery items.

(ii) Supervision & Administration, Project Development, and Overhead

The CPA expressed the belief that the $1,000,000 and $1,030,000 figures given respectively for Supervision & Administration and Project Development (both elements of Project Management) are high for the size of the project, particularly given that some $1,080,000 is proposed separately for Overhead.

ANG submitted that the negotiating and coordinating efforts for the project involve many shippers and other transmission companies, and are being done against a backdrop of rapidly changing regulatory and commercial conditions. ANG noted that as indirect costs are not directly proportional to the magnitude of the project, they can represent a significant percentage of the overall cost of a relatively small project such as the proposed expansion. ANG maintained that, in view of the foregoing, the project management costs are reasonable and appropriate to the nature of the project.

(iii) Cost Impact of PGT's Second Open Season

In response to an information request from the CPA, ANG reported that the Company's cost estimate given for Project Management had not changed since its May 1990 filing. ANG noted that while some components of the Project Management cost estimate were up, others were down, and that on balance the originally filed estimate remained appropriate. ANG noted as an example that the Project Development cost was expected to increase, largely as the result of the second FERC open season proceedings.

On this point, the CPA argued that any costs associated with ANG's participation in the FERC proceedings were not appropriate costs to be included in the capital cost estimate.

ANG replied that it was not a party to PGT's second open season proceeding before the FERC and did not incur any participation costs. ANG went on to note, however, that the number of expansion shippers increased substantially as a result of those proceedings, thereby generating additional costs with regard to shipper negotiations and regulatory requirements.

(iv) Contingency

The CPA submitted that ANG's $6,560,000 provision for contingency was too high, given the scope of the project and the current economic climate. The CPA contended that, since ANG is merely adding to three compressor stations, the materials costs and costs for contractors and labour should all be estimable with a fair degree of accuracy. Furthermore, the CPA expressed the view that there is no change in the Alberta or B.C. economies visible for the next several years to suggest that contractor and labour costs may suddenly accelerate to create unforeseen jumps in the forecast installation costs.

The CPA concluded that a contingency in the order of five percent on the materials and installation costs ($2,956,000) would provide sufficient cushion against unforeseen costs and would also provide an incentive to ANG to control its costs.

ANG argued in reply that it conducted a thorough analysis of all the major cost elements to arrive at its estimated weighted average for contingency. ANG noted further that any construction cost variances that are realized will be open to review, either through ANG's negotiating process with its shippers and the industry associations or by a formal Board proceeding in accordance with "complaints basis" regulation.

(v) Allowance for Funds Used During Construction

In response to an information request from the CPA, ANG reported that it had used an 11.77 percent cost rate for AFUDC, a percentage equal to the Company's current rate of return on rate base.

The CPA argued that this AFUDC cost rate was excessive in light of the prevailing low interest rates, forecasted by the CPA to stay in the 9 to 10 percent range (if not lower) during 1992. The CPA also questioned the appropriateness of ANG collecting AFUDC of $50,000 for the period preceding its May 1990 application filing date. Furthermore, the CPA suggested that ANG's initial estimate for AFUDC was no longer valid due to delays having being encountered in the Company's construction schedule.

ANG argued in reply that the provision for AFUDC was estimated by a conventional industry calculation which applies Board-approved rates of return directly to the forecasted spending profile for the expansion, and that the actual AFUDC incurred by the project would be calculated by applying the then approved rates of return to the actual expenditure profile. In conclusion, ANG submitted that its method of calculating AFUDC was correct and that its AFUDC estimate should be accepted by the Board.

Views of the Board

Cost is one of the many factors that the Board takes into account when determining whether a project applied for under Part III of the Act is in the public interest.

The Board recognizes that a cost estimate made at the time of a Part III application may differ from the eventual cost of a project. The Board would like to clarify that rate base additions are based on actual rather than forecasted costs. The Board would also like to remind parties that they are free to question the prudency of ANG's incurred capital expenditures through the complaints mechanism.

With respect to the specific issues raised by the CPA, the Board would like to make the following comments:

(i) Engineering

The Board accepts ANG's argument that the bulk of the detailed engineering and design work for the expansion project remains to be done.

(ii) Supervision & Administration, Project Development, and Overhead

The Board accepts ANG's argument that the relatively high cost estimates for Supervision & Administration, Project Development, and Overhead are justified by the unusually high degree of shipper negotiation and external coordination associated with the expansion project.

The Board wishes to advise ANG, however, that expenditures in these categories may be audited by the Board in order to verify that they are project-related.

(iii) Cost Impact of PGT's Second Open Season

The Board is satisfied with ANG's explanation for the projected increase in the cost of Project Development resulting from PGT's second open season.

(iv) Contingency

The Board shares the CPA's concern that ANG's provision for contingency appears to be high, given the nature of the project and the current economic climate.

So that it may effectively track cost variances, the Board has decided to include in any approval order it might issue a condition requiring ANG to submit bimonthly construction progress and cost reports. These reports should include the completion percentage of each construction activity, a breakdown of costs incurred during the preceding two months, and an update of projected costs to complete the project.

Such a condition would also require that ANG provide copies of these bimonthly reports to any other party who so requests.

The Board will monitor ANG's contingency expenditures and ensure that any of significance are properly justified before being allowed in the Company's rate base.

(v) Allowance for Funds Used During Construction

In the past, it has been the Board's general practice to provide for AFUDC at a rate equal to the pipeline company's rate of return on rate base. This practice is designed to give a company the financial flexibility to fund capital assets on a long-term basis (in a manner similar to the funding of the company's rate base) when in its judgement it is appropriate to do so. The Board therefore has no objection to ANG's use of its rate of return on rate base as its AFUDC cost rate for this project.

With regard to the second point raised by the CPA, the Board considers the charges incurred by ANG prior to the application filing date to be in the nature of "preliminary survey and investigation charges". The Board considers these preliminary costs, as well as the associated carrying charges, to be legitimate rate base expenditures.

With respect to the CPA's final comment respecting project delays, the Board wishes to confirm that the amount of AFUDC actually allowed into rate base will be calculated on the basis of the actual (as opposed to the forecasted) expenditure profile.

Chapter 6

Environmental and Land Matters

6.1 Early Public Notification

ANG submitted that it had notified the B.C. Ministry of Energy, Mines and Petroleum Resources regarding the proposed project.

Views of the Board

Since the entire project is to be constructed within ANG property, and since the Company has contacted the appropriate provincial ministry, it is the Board's view that ANG has implemented an adequate early public notification program.

6.2 Land Use

ANG has applied for additions and modifications to compressor facilities only. All additional and modified facilities required in connection with this project would be located on existing station sites. No additional land would be required for those facilities.

Views of the Board

In the Board's view, since ANG plans to locate all additional and modified facilities on existing station sites, the impact on land use would be insignificant.

6.3 Environmental Matters

In its application, ANG stated that any potentially adverse environmental effects resulting from the installation and operation of the expanded compressor facilities would be insignificant or mitigable with known technology. ANG also stated that it would comply with all federal and provincial environmental regulations currently in place which would affect the expansion facilities.

The B.C. Ministry of Energy, Mines and Petroleum Resources, on behalf of the Province of B.C., requested that ANG provide the background studies and documents from which the Company had drawn the above conclusion. In its response, ANG submitted that it had undertaken an extensive review of the environmental regulations, both existing and those in draft form, governing the facilities proposed to be added to its pipeline system during 1993. Furthermore, ANG noted that it had held meetings with personnel of the B.C. Ministry of Environment, Lands and Parks both in Victoria and at the local Waste Management Branch level.

ANG further submitted that it would be preparing a formal "Environmental Impact Analysis" detailing the procedures the Company would follow to mitigate the potentially adverse environmental effects associated with the construction and operation of the expansion facilities.

Views of the Board

The environmental impacts of the project were considered under two different processes: an environmental screening of the application pursuant to the *Environmental Assessment and Review Process Guidelines Order* ("EARP Guidelines Order"), to the extent that there was no duplication with the Board's own regulatory process, and a project review pursuant to the Board's mandate under Part III of the Act. As part of those procedures, the comments of interested parties were invited with respect to the environmental screening of the application.

Based on its review of the environmental information contained in ANG's application and subsequent information filed by the Company respecting the potential effects which could result from the proposal, the Board has determined pursuant to paragraph 12(c) of the EARP Guidelines Order that the potentially adverse environmental effects which may be caused by the construction and operation of the applied-for facilities, including the social effects directly related thereto, would be insignificant or mitigable with known technology. Furthermore, the Board is satisfied that ANG would comply with all federal and provincial regulations currently in place which would affect the expansion facilities.

The Board is satisfied with the environmental information provided by ANG respecting the proposed expansion project, and accepts ANG's undertaking to prepare a formal Environmental Impact Analysis.

The Board has decided to include in any approval order it might issue a condition requiring ANG to file its Environmental Impact Analysis. Such a condition would also require that ANG not commence construction until the Company has first received the Board's approval of the environmental impact mitigation procedures contained therein.

So that it can determine whether the environmental objectives have been achieved, the Board has decided to include in any approval order it might issue a condition requiring ANG to file, for Board approval, a post-construction environmental report within six months of the in-service date for the expansion facilities. The report should address the environmental issues that have arisen up to that time. The report should also discuss the status of each issue and the measures to be implemented for the resolution of any outstanding issues.

Chapter 7

Toll and Tariff Matters

7.1 Toll Methodology

ANG proposed that the cost of the expansion facilities be tolled on a rolled-in basis with existing facilities.

ANG forecasted that tolling the expansion on a rolled-in basis would result in an approximate doubling of its toll. For 1994, ANG estimates the toll would increase from approximately 4.0¢/Mcf to about 8.2¢/Mcf. By comparison, if the new facilities were tolled incrementally, the 1994 toll would be about 14.7¢/Mcf. On a rolled-in basis, the ANG toll would represent somewhat less than 10 percent of the total cost of transportation from the Alberta/B.C. border to the southern California market.

Amoco was the only interested party that opposed ANG's proposal to use a rolled-in tolling methodology, advocating instead an incremental tolling regime. Amoco argued that existing shippers were being asked to subsidize the expansion through a doubling of ANG's tolls without obtaining any added benefits and maintained that such a subsidy amounted to a fundamentally unfair rate treatment. Amoco also submitted that the proposed expansion would result in a likelihood of underutilization of pipeline facilities and displacement of existing markets for and supplies of Canadian gas.

ANG argued that the magnitude of the toll increase was due to the fact that its current tolls are calculated using a rate base that is a small fraction of its original cost, due primarily to the age of the existing facilities. In support of its position to use a rolled-in methodology, ANG pointed to the Board's GH-5-89 decision wherein the Board stated that:

> *"the Board is of the view that existing shippers have no vested rights in the TransCanada system and, hence, they have no vested right to be protected from toll increases which come about from economically feasible expansions of the system."*[1]

Views of the Board

The Board notes that only one party suggested that a rolled-in treatment of the expansion costs would be unfair.

On the basis of the limited evidence provided in this proceeding, the Board has not been persuaded to implement any change in ANG's tolling methodology.

7.2 Financial Assurances

ANG stated that the expansion facilities will be financed through bank lines of credit and/or commercial paper and internal cash flow. Since the building and operation of the facility amounts to a significant capital outlay and the Firm Service Agreements are for a minimum

1. Reference page 27 of Volume 1 "Tolling and Economic Feasibility" of GH-5-89 Reasons for Decision, dated November 1990.

duration of 15 years, ANG decided that all shippers had to demonstrate their creditworthiness by providing one of the following:

(1) A bond rating by a Canadian or U.S. rating agency of investment grade or better;

(2) A corporate guarantee by an affiliate with a bond rating by a Canadian or U.S. rating agency of investment grade or better;

(3) A one-year evergreening letter of credit from a major bank for the duration of the Firm Service Agreements for a value equal to one year of transportation charges, plus additional security relating to markets and supply for shippers with daily volumes greater than 10 MMcfd (283 $10^3m^3/d$); or

(4) A letter of credit or purchase of ANG commercial paper or an equivalent investment assigned to ANG equal to 1.5 years of transportation charges under a Firm Service Agreement held under a trust agreement as security for a shipper's financial obligations during the term of the Firm Service Agreement.

Vector and CanWest argued that the financial assurances required of them, specifically a letter of credit for a time period of 18 months, were excessive. Vector requested that the Board review the requirement for the letter of credit and reduce the time period to three months. CanWest proposed that no line of credit or financial assurances be required at all.

ANG noted in argument that its tariff provides it with flexibility in determining the creditworthiness of its prospective shippers. While recognizing the concerns of CanWest and Vector, ANG maintained that the financial assurances requested represent an appropriate balance between shippers which felt the criteria were too stringent and those which were concerned that they were not stringent enough.

Views of the Board

The Board believes that the granting of credit requires the exercise of informed judgement and that the pipeline company is in the best position to judge the creditworthiness of its customers. Neither Vector nor CanWest has brought any significant facts or circumstances to the Board's attention that would cause it to alter this view.

The Board finds, in the circumstances of this case, that the criteria used by ANG to establish both the need for and the appropriate level of financial assurances were applied in a non-discriminatory manner, and that the financial assurances required by ANG for this expansion are not unreasonable.

The Board has decided not to direct ANG to modify its current tariff provisions in respect of financial assurances.

Chapter 8
Economic Feasibility

As indicated in its GH-5-89 Reasons for Decision, the Board determines economic feasibility by assessing the likelihood that the applied-for facilities will be used at a reasonable level over their economic life and that the associated demand charges will be paid[1].

In ANG's view, concrete evidence that the expansion facilities will be used at reasonable levels and that the associated demand charges will be paid has been provided in the form of binding, unconditional firm transportation contracts, backed by financial assurances.

ANG expressed the belief that these contractual and financial obligations provide shippers with the incentive to maximize use of their contracted ANG expansion capacity, particularly when these commitments are combined with corresponding obligations on upstream and downstream pipeline facilities.

ANG submitted that the economic feasibility of the expansion facilities has been further supported in the context of the GHW-2-91 proceeding through the demonstration of overall gas supply availability and market need.

In response to concerns raised by certain interested parties over the relative lack of project-specific market information, ANG again pointed to the strength of the associated transportation contracts. ANG submitted in this regard that binding and unconditional transportation contracts, backed by financial assurances, provide the Board with better evidence of the strength of transportation-only projects like the ANG expansion than can be obtained by the detailed supply and market information associated with export applications under Part VI of the Act.

Views of the Board

In the view of the Board, the unconditional firm transportation contracts signed by the prospective expansion shippers provide strong, although not conclusive, evidence that the expansion facilities would be used at a reasonable level over their economic life and that the associated demand charges would be paid.

In determining whether the expansion facilities are in the public interest, the Board has also taken into account the overall supply and market information filed in support of the application together with the available project-specific supply and market information, as well as information provided in respect of the competitiveness of Canadian-sourced gas in the California and Pacific Northwest markets targeted by the expansion (reference Chapters 2 and 3). The Board believes that this evidence, coupled with the existence of executed long-term, unconditional firm service transportation contracts on the ANG and PGT systems for the entire expansion volume, satisfactorily demonstrates that markets will exist in California and the Pacific Northwest for the expansion volumes, and that Canadian-sourced gas could be competitive in those markets.

Moreover, the Board is of the view that the toll increase on ANG that would be caused by the expansion would not result in reduced demand for firm service on the system.

In conclusion, the Board is satisfied that the ANG expansion facilities would be used at a reasonable level over their economic life and that the associated demand charges would be paid.

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1. Reference section 3.2.1 of Volume 1 "Tolling and Economic Feasibility" of GH-5-89 Reasons for Decision, dated November 1990.

Chapter 9
Disposition

On the basis of all the foregoing, the Board finds that the applied-for expansion facilities are in the public interest. Accordingly, the Board has issued, pursuant to section 58 of the Act, Order XG-16-92 (Appendix II) exempting ANG from the provisions of sections 30, 31, and 47 of the Act in respect of the expansion facilities.

The foregoing chapters, together with Order XG-16-92, constitute the Board's Reasons for Decision on this application.

R. Priddle
Presiding Member

C. Bélanger
Member

J.-G. Fredette
Member

R. Illing
Member

R.B. Horner
Member

K.W. Vollman
Member

A.B. Gilmour
Member

R. Andrew
Member

A. Côté-Verhaaf
Member

Appendix I

Project-specific Gas Supply Arrangements

TABLE I-1

Summary of Producers'/Aggregators' Supply Arrangements

Shipper/Producer	Corporate or Dedicated	Total Reserves $10^9 m^3$ (Bcf)	Total Requirements $10^9 m^3$ (Bcf)	Comments
1. CanWest	Corporate	67.1 (2380)	55.3 (1950)	As of 1 Nov 1991
2. Chevron	Np	42.2 (1490)	NP	Exact supply source to be finalized by early 1992
3. DEKALB	Corporate	9.9 (350)	4.2 (150)	
4. Norcen	Dedicated	7.9 (278)	7.3 (257)	
5. NCMI	See NCO	NP	NP	Purchasing from NCO
6. NCO	Corporate	NP	NP	Not finalized
7. PanAlberta	Dedicated	11.8 (418)	9.2 (325)	Contracted supply from 11 producers for 15 years
8. PanCanadian	Corporate	9.8 (346)	NP	As of year-end 1990
9. Pancontinental	NP	NP	NP	Inverness Petroleum is the supplier
10. Paramount	Corporate	10.0 (352)	0.9 $10^9 m^3$/yr (31.4 Bcf/yr)	Requirements include interruptible spot sales
11. Petro-Canada	Corporate	70.8 (2500)	NP	As of year-end 1990
12. Shell	Corporate	41.5 (1460)	33.1 (1170)	
13. Suncor	Corporate	5.0 (176)	0.8 (29)	

NP - Not provided by Shipper

TABLE I-2

Summary of Marketers' Supply Arrangements

Shipper/Marketer	Supplier	Daily Volume $10^3m^3/d$ (MMcfd)	Term Volume 10^9m^3 (Bcf)	Comments
1. Northridge	Unknown	NP	NP	
2. Vector	Ulster Petroleum	486 (17)	2.7 (94)	15-year contract

NP - Not provided by shipper

TABLE I-3

Summary of U.S. Buyers' Supply Arrangements

Shipper/Buyer	Supplier Dedicated	Daily Volume $10^3m^3/d$ (MMcfd)	Term (Years)	Comments
1. Cascade	See IGI	NP	NP	Purchasing from IGI Resources
2. Burbank 3. Glendale 4. Pasadena	Unigas Unigas Unigas	136.0 (4.8) 113.3 (4.0) 113.3 (4.0)	6 6 6	Evergreening provision Evergreening provision Evergreening provision
5. C.P. National	See WWP			
6. IGI	Unigas Grand Valley Poco	70.8 (2.5) 198.3 (7.0) 566.6 (20)	15 15 8	Letter of intent Letter of intent Contract
7. NCPA	NP	NP	NP	Expect contracts to be February 92
8. Northwest Natural Gas	Poco Summit Unigas	445.1 (15.7) 219.2 (7.7) 657.8 (23.2)	10 7 10	
9. SMUD	NP	NP	NP	No supply contracts finalized
10. SDG&E	Husky Oil CanHunter Summit Bow Valley	616.5 (21.9) 563.5 (20.0) 197.2 (7.0) 141.0 (5.0)	10 10 8 11	
11. SoCal Edison	Esso AEC Shell WGML	1481 (52.3) 1481 (52.3) 1475 (52.0) 1481 (52.3)	15 15 15 15	
12. Washington Energy	NP	NP	NP	Supply contracts pending execution of market contracts
13. WWP	AEC Amerada Hess PanCanadian	Variable Variable Variable	10 7 10	Term may be extended

NP - Not provided by shipper

Appendix II

Project-Specific Market Arrangements

Expansion Shipper	Shipper Description	Intended Market
(1) CanWest Gas Supply Inc.	B.C. gas supply aggregator.	California
(2) Cascade Natural Gas Corporation	U.S. LDC which serves the states of Washington and Oregon. Cascade has contracted to purchase Canadian gas from IGI Resources, Inc.	Pacific Northwest
(3) Chevron Canada Resources	Canadian gas producer.	Pacific Northwest and California through its U.S. affiliate Chevron, U.S.A. Inc.
(4) The City of Burbank	Southern California municipal electric utility.	Burbank intends to use the gas for its California utility electrical generation ("UEG") market.
(5) The City of Glendale	Southern California municipal electric utility.	Glendale intends to use the gas for its California UEG market.
(6) The City of Pasadena	Southern California municipal electric utility.	Pasadena intends to use the gas for its California UEG market.
(7) C.P. National Corporation	U.S. LDC serving the states of Oregon and California.	Pacific Northwest and California.
(8) DEKALB Energy Canada Ltd.	Canadian gas producer.	California
(9) IGI Resources, Inc.	U.S. gas marketer.	Pacific Northwest, including sales to IGI and Intermountain Gas Company, a U.S. LDC serving southern Idaho.
(10) Norcen Energy Resources Limited	Canadian gas producer.	California
(11) North Canadian Marketing, Inc.	Wholly-owned subsidiary of North Canadian Oils Limited.	California
(12) North Canadian Oils Limited	Canadian gas producer.	California
(13) Northern California Power Agency	A "California Joint Power Agency and Public Entity" comprised of northern California utilities intending to serve gas-fired electric generating facilities owned and operated by its members.	California
(14) Northridge Alberta Gas Sales Ltd.	Canadian gas marketer.	California
(15) Northwest Natural Gas Company	U.S. LDC serving Oregon and Washington.	Pacific Northwest

Expansion Shipper	Shipper Description	Intended Market
(16) Pan-Alberta Gas Ltd.	Canadian gas aggregator and marketer.	California, in accordance with an executed gas sales contract with Natural Gas Clearinghouse. The gas will be marketed through Pan-Alberta's wholly-owned U.S. marketing company, Pan-Alberta Gas (U.S.) Inc.
(17) PanCanadian Petroleum Limited	Alberta gas producer.	Pacific Northwest and California.
(18) Pancontinental Oil, Ltd.	Inverness Petroleum Ltd., a Canadian gas producer, is the successor, in interest, to Pancontinental. Inverness intends to market its own gas supplies.	California
(19) Paramount Resources Ltd.	Canadian gas exploration, development; production and marketing company.	California, through its wholly-owned U.S. subsidiary, Paramount Resources U.S. Inc.
(20) Petro-Canada	Canadian gas producer.	California through Gas Mark, Inc., a California gas marketer.
(21) Sacramento Municipal Utility District	A municipal electric utility serving the greater Sacramento area which intends to use the Canadian gas in its gas-fired electric generating facilities.	California
(22) Shell Canada Limited	Canadian gas producer.	California through its wholly-owned subsidiary Salmon Resources Limited.
(23) San Diego Gas & Electric Company	U.S. investor-owned public gas and electric utility serving the San Diego and Orange counties in Southern California.	California
(24) Southern California Edison Company	Electric utility which provides electrical services to communities in central and southern California.	California
(25) Suncor Inc.	Canadian gas producer.	California
(26) Vector Energy, Inc.	Canadian gas marketer.	California
(27) Washington Energy Exploration, Inc.	U.S. oil and gas producer and marketer.	Pacific Northwest and California. The gas in the Pacific Northwest will be marketed through an affiliate, Washington Natural Gas Company, an LDC serving the Puget Sound area.
(28) Washington Water Power	Combined gas and electric utility serving eastern Washington and Northern Idaho. Water Power has recently purchased certain assets of C.P. National, an LDC serving Oregon and California.	Pacific Northwest

Order XG-16-92

IN THE MATTER OF the *National Energy Board Act* ("the Act") and the regulations made thereunder; and

IN THE MATTER OF an application, pursuant to Part III of the Act, by Alberta Natural Gas Company Ltd. ("ANG"); filed with the Board under File 3400-A2-11.

B E F O R E the Board on 4 May 1992.

WHEREAS the Board has received an application from ANG dated 31 May 1990 for an order pursuant to section 58 of the Act exempting ANG from the provisions of sections 30, 31, and 47 of the Act in respect of certain facilities proposed to be added to its pipeline system;

AND WHEREAS ANG filed with the Board, under covering letter dated 2 October 1991, a series of amendments to the application;

AND WHEREAS the Board, pursuant to Order GHW-2-91, solicited written submissions from interested parties on the application;

AND WHEREAS, pursuant to the *Environmental Assessment and Review Process Guidelines Order* ("EARP Guidelines Order"), the Board has considered the information submitted by ANG;

AND WHEREAS the Board has determined, pursuant to paragraph 12(c) of the EARP Guidelines Order, that the potentially adverse environmental effects which may be caused by the proposed facilities, including the social effects directly related to those environmental effects, are insignificant or mitigable with known technology;

AND WHEREAS the Board has examined the application, as amended, together with all written submissions by interested parties and ANG's reply comments thereto, and considers it to be in the public interest to grant the relief requested therein;

IT IS ORDERED THAT, pursuant to section 58 of the Act, the facilities proposed to be added to ANG's pipeline system, as described in Schedule A attached to and forming part of this Order, are exempt from the provisions of sections 30, 31, and 47 of the Act,

upon the following conditions:

1. Unless the Board otherwise directs, ANG shall file with the Board, prior to the commencement of construction, copies of all executed final transportation agreements with Foothills Pipe Lines Ltd. and Foothills Pipe Lines (South B.C.) Ltd. relating to the expansion project.

2. Unless the Board otherwise directs, ANG shall, prior to the commencement of construction, demonstrate to the satisfaction of the Board that all requisite U.S. regulatory approvals have been granted in respect of any necessary downstream transportation facilities and transportation services.

3. ANG shall file with the Board a copy of its Environmental Impact Analysis and shall not commence construction without having first received the Board's approval of the environmental impact mitigation procedures contained therein.

4. During construction, ANG shall file with the Board as well as any interested party who so requests in writing, in a format to be determined in consultation with Board staff, bimonthly construction progress and cost reports providing the completion percentage of each construction activity, a breakdown of costs incurred during the preceding two months, and an update of projected costs to complete the project.

5. ANG shall, both during and after the construction period, monitor the effects of the construction of the expansion facilities upon the environment and shall submit, within six months of the facilities being placed in service, a report satisfactory to the Board describing such effects. This report shall include the results of the monitoring programs and the actions taken or which will be taken to prevent or mitigate any long-term effects of construction upon farmlands and the environment.

6. Unless the Board otherwise directs, ANG shall cause the construction and installation of the facilities exempted by this Order to be commenced on or before 31 December 1993.

NATIONAL ENERGY BOARD

G.A. Laing
Secretary

Schedule A

Alberta Natural Gas Company Ltd.
Description of Applied-For Facilities

Compressor Station No. 1

Installation of two additional compressor units in separate buildings, replacement of three aerodynamic assemblies, additional gas scrubbing capacity, an additional control building, additional cooling capacity, and piping additions (to provide a power increase of 28 MW).

Compressor Station No. 2A

Installation of cooling facilities, replacement of an aerodynamic assembly, additions and modifications to yard piping, replacement of the existing gas scrubber, and the addition of a second gas scrubber.

Compressor Station No. 2B

Installation of an additional compressor unit in a separate building, control additions in the existing control building, replacement of an aerodynamic assembly, additions and modifications to the yard piping, and installation of an additional gas scrubber (to provide a power increase of 14 MW).